Evaluation of
Coalbed Methane
Well Types
in the
San Juan Basin

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Prepared by

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1.0 BACKGROUND

Malkewicz Hueni Associates, Inc. (MHA) received a Task Order from the U. S. Bureau of Land Management (BLM) to evaluate the production behavior of different types of coalbed methane wells in the San Juan Basin, including horizontal wells. This report provides the results of the study and is composed of three main subject areas:

1. Literature review of the application of horizontal wells in coal seams.
2. Comparison of gas recovery performance using vertical, horizontal and directional gas wells in the San Juan Basin.
3. Capturing the current industry position on horizontal and directional drilling in San Juan Basin.

MHA has made every effort to maintain an unbiased approach in this investigation while remaining fully aware that the results of the study may not totally agree with those of other interested parties such as active oil and gas operators in San Juan Basin, environmental groups, concerned citizens and governmental agencies. This study was conducted by researching technical and trade publications of the oil and gas industry and by interviewing several San Juan Basin producing companies. Therefore, conclusions offered herein are derived from the findings of industry technical experts and from operators who participated in providing their company's perspective on the topic.

2.0 SUMMARY

Despite the success of horizontal and directional drilling in conventional oil and gas reservoirs over the past couple of decades, application of such drilling techniques in coal bed methane (CBM) reservoirs has so far produced mixed results. The drilling technology itself has enjoyed significant progress in recent years and it appears that the technical expertise of the leading drilling companies to directionally or horizontally drill wells today in the San Juan Basin is currently at a high level. Furthermore, research and modeling work aimed at understanding the production characteristics of deviated wellbores in coal seams and coal mines over the past two decades have laid a sound foundation for continued improvement of this technology.

Despite these developments, however, significant technical challenges remain to be addressed before deviated and horizontal wells are adopted overwhelmingly by the industry. These include, but are not limited to, wellbore mechanical stability, effective stimulation, improved completion techniques, artificial lift, drilling cost, reservoir-wellbore connectivity issues and long-term productivity.

As the angle of deviation exceeds a critical threshold of about 30-35 degrees, these technical challenges become even more important, reaching their highest level for the case of horizontal wellbores. Further research and development is needed to address these issues before the industry feels comfortable with the risk/reward aspect of horizontal drilling in CBM and its ability to predict both short- and long-term performance. At the present time, the general consensus of the oil and gas operators in the San Juan Basin is that the horizontal and/or directional drilling offers the potential to add reserves and decrease drilling density. However, performance of the horizontal and deviated wells to-date has not precipitated widespread acceptance of this technology in the San Juan Basin. As a consequence, smaller operators appear to face difficulties in securing financing from bankers to apply these drilling techniques as this technology is perceived to be unreliable in providing higher rates and reserves. Similarly, pipeline companies are reluctant to commit resources on the development of surface infrastructure at the present time without a guarantee of sustainable, long term production growth from the producing companies.

A review of the performance of both the recent and older sets of horizontal and highly deviated wells in the San Juan Basin indicates that both types of wells have, on average, higher initial rates but in the longer term perform poorer than expected because of mechanical problems such as plugging with coal fines, wellbore stability, and loading of fluids in the deviated sections. Recent performance data for newer wells, however, appears to indicate that that industry is beginning to make significant progress in addressing some of these technical challenges. Horizontal and highly deviated CBM wells in the San Juan Basin cost between two (2) and four (4) times more than a vertical well, but do not usually provide a commensurate increase in rate and reserves; hence they may not be economically attractive at the present time. There have been encouraging rates exhibited in recently drilled wells and, if continued, will certainly work in favor of horizontal and deviated drilling. Based on a review of industry production data, horizontal wells have exhibited an average improvement in rate and recovery of between 1.1 and 1.6 times that of an average vertical well offsetting the horizontal well. The average highly deviated well has not demonstrated this improvement, exhibiting an average rate and reserve improvement of between 0.8 and 0.9 times that of an average vertical well offsetting the deviated well.

Another challenge facing the operators is finding areas where reservoir rock properties and geologic settings are favorable for horizontal drilling. For instance, in the fairway region of San Juan Basin (New Mexico) where the coals are more permeable and have higher fracture density, the stress environment is such that horizontal wells have a higher probability of experiencing mechanical failure than in the tighter regions further north in Colorado. However, these northern regions have historically been producing at a much lower rate than the Fairway wells, which brings into focus the issue of risk and potential reward in horizontal drilling. In addition, horizontal wells can be drilled more economically if the majority of the gas is stored in a single, thick coal seam with significant lateral continuity. The eastern portion of the Northern San Juan Basin EIS study has lower permeability, but relatively thick coal in two distinct coal intervals. The western portion of the area, however, has very different geological characteristics from the eastern area and is characterized by multiple distinct coal seams. The impact of reservoir geology on the long term performance of horizontal wells in San Juan coal has not yet been fully evaluated. It is anticipated that with a modest surge in horizontal and directional drilling in the last couple of years, significant learning and technological development will be achieved over the next 2-5 years.

3.0 INTRODUCTION

The exploitation of CBM requires a full understanding and knowledge of coal reservoir geologic characteristics, gas desorption mechanism and fluid flow behavior in coal beds, drilling and completion practices, surface facilities and a myriad of environmental issues. In general, industry operational practices endeavor to maximize production, reduce costs, enhance operational safety, and mitigate the environmental damage inherent in such operations. New technologies have been developed to help companies achieve these objectives and they represent improvements over the older technologies.

There are generally four types of wellbores used in the San Juan Basin for CBM production: (a) vertical, (b) directional, (c) horizontal, and (d) multilateral. These have also been referred to as deviated wells, slant-hole wells and s-turn wells by the oil and gas literature and they are all considered some form of directional drilling.

Horizontal wells are defined as wells deviated more than 75 degrees from vertical (Lacy et al. 1991). Their primary purpose is to track the oil- or gas-bearing rock in order to maximize production rate and recovery. The three primary types of horizontal wells are Short-Radius, Medium-Radius and Long-Radius wellbores.

Multilateral wells entail drilling two or more horizontal legs from a single vertical well in order to maximize exposure to the oil- or gas-bearing strata. Multilateral drilling represents the newest of such techniques with the least industry experience. Vertical wells constitute by far the majority of wells drilled in San Juan Basin. Years of experience, reliability, and lower drilling and maintenance costs characterize the primary advantages of vertical wells. Vertical wells, however, have to be drilled with closer well spacing to improve sweep efficiency and maximize production. This puts the vertical wells at a disadvantage relative to directional or horizontal wells as it leads to increased environmental impact resulting from surface disturbance associated with drilling activity. Alternatively, multilateral drilling minimizes surface disturbances to the maximum degree and, hence, is ideal for environmentally sensitive areas in the Basin. These types of wells, however, are significantly more expensive to drill, are in a higher risk category from an investment point of view, and have not yet established a proven track record for their technical superiority over the conventional vertical wells. Directional wells with a deviation angle less than 30 degrees are being drilled with more frequency in the San Juan Basin because stimulation and completion techniques developed extensively for vertical wells can be applied to these wells with only slight modifications. Furthermore, this type of technology is often ideal when there are certain limitations for drill pad placement such as topographical features and/or surface cultural layout.

4.0 CONCLUSIONS

1. San Juan Basin horizontal and deviated CBM wells on average have higher initial rates but their longer term performance has been poorer than expected because of mechanical problems related to plugging with coal fines, wellbore stability, and loading of fluids in the deviated section. While very recent drilling, particularly by CDX Gas suggests that some of these problems are being overcome, additional time is needed to verify longer term stability and improved rate performance for these wells.

2. MHA reviewed the San Juan Basin CBM performance of 17 horizontal wells, 13 highly deviated wells, and 71 vertical wells that immediately offset the horizontal and highly deviated wells. Two comparison methods were used. The first method determined a 'performance index' derived by comparing both the EUR and the maximum annual producing rate of the horizontal or deviated well with the same values for the offsetting vertical well(s). The performance index was calculated by taking half the quotient of the horizontal well EUR divided by the average offsetting vertical well EUR and adding half the quotient of the horizontal well maximum annual rate divided by the maximum annual rate of the average offsetting vertical well. A value of one would imply that there was essentially no difference in performance. The second method compared the average rate of the horizontal or deviated well with that of the offsetting vertical wells for the same calendar time period. A value greater than one indicates that the horizontal or deviated well produced at a higher average rate than the average offsetting vertical well over the same time period. While clearly evaluating different performance measures, both methods gave similar overall results.

3. The difference in the performance of horizontal or deviated wells compared with offsetting vertical wells varies dramatically. Based on the available data, there does not appear to be a strong correlation to geographic location within the San Juan Basin. Based on the performance index defined above, the 17 horizontal wells exhibited performance indices ranging from zero (complete failure) to 7.5, with an average of 1.6. Based on the comparison of average horizontal well rate with the rate of offsetting vertical wells over the same time frame, the variation was 0.1 to 5.1, with an average of 1.3. For the 13 highly deviated wells examined in this study the performance indices varied from 0.2 to 1.4, with an average of 0.8. Based on the comparison of average highly deviated well rate with the rate of offsetting vertical wells over the same time frame, the variation was 0.2 to 1.5, with an average of 0.9.

4. Horizontal or highly deviated CBM wells generally cost between two (2) and four (4) times that of vertical wells to drill and complete. Production and reserves increases have not been commensurate with these increased costs. The average horizontal well exhibits an improvement over offsetting vertical wells of between 1.1 and 1.6 times the average maximum annual rate and estimated ultimate recovery (EUR). On the other hand, the average deviated well has exhibited poorer performance, exhibiting maximum annual rates and EURs of between 80 and 90 percent of the offsetting vertical wells. These conclusions regarding performance are based on a statistical analysis of wells in the San

Juan Basin and do not reflect a detailed technical analysis of each non-vertical well cited in this study.

5. Two wells drilled recently by CDX Gas have provided very encouraging performance improvement compared to offsetting vertical wells. The Penrose 1R in Section 8-R32N-R6W of La Plata County, Colorado was initially completed June 2002 but experienced mechanical difficulties requiring substantial time and resources to remedy (some of the problems may have been with surface or facility issues). However, in the second half of 2003 the Penrose 1R gas rate increased to 2.2 MMCFD and reportedly remains substantially choked back to avoid reservoir drawdown that could precipitate hole problems in the laterals. The Anderson 1R in the adjacent Section 5 was completed in December 2002 and apparently had similar mechanical difficulties to that of the Penrose 1R. However, these problems also seem to have been corrected as the Anderson 1R exhibited an increasing rate in the second half of 2003 reaching a stable rate of approximately one (1) MMCFD. These CDX well rates compare with offsetting vertical well rates of about 100 to 300 MCFD, or 10 to 20 percent of the CDX wells. Although CDX has not provided many details concerning these recent horizontal wells, they are believed to employ one or two sets of 'pitchfork' laterals, each pitchfork having three laterals located 650 feet apart from one another and extending about one-half mile into the reservoir. While these two CDX wells appear very promising, more information and production history is required to confirm their potential.

6. Detailed analysis is needed to address variations in economic viability of horizontal and deviated wells in different parts of the San Juan Basin. The basin clearly exhibits areas where there are several substantial coal seams that may require multiple laterals to exploit and the statistical comparison used in this analysis may not provide an accurate assessment of the development potential using horizontal wells. In addition, the wide variation in performance of horizontal wells in the San Juan Basin suggests that there are many factors, including geologic heterogeneity, influencing performance. Therefore, there is no general application for horizontal wells to the development of the Fruitland Coal in the San Juan Basin. Because of the variation of these many factors locally throughout the basin, the feasibility must be evaluated on a location by location basis as the success of any particular horizontal well appears to be highly site specific.

7. Horizontal drilling in San Juan basin is currently experiencing an increased level of interest by a number of oil and gas operators. A series of new wells ranging from low deviation to multi-lateral horizontal have been recently drilled in various parts of the Basin. These activities are driven by the potential that horizontal wells can be superior to vertical wells in both increased production rate and reserve addition while at the same time reduce the environmental impact associated with higher density wells. Although the evidence to-date is mixed regarding the rate and reserve benefits of horizontal wells, operators seem optimistic that additional technical breakthroughs and production history will demonstrate that horizontal and highly deviated wells will become an economically viable option as an alternative to conventional vertical wells in the Basin. At the current level of research and development by various operators in San Juan Basin, it is

anticipated that major breakthroughs and better understanding of horizontal drilling technology may be achievable within the next 2 to 5 years.

8. Technical uncertainties in deviated wells increase rapidly when the angle of deviation exceeds 30 to 35 degrees from vertical. San Juan Basin operators seem to have developed expertise to manage lesser deviated wells; however, wells with these limited deviations do not offer a significant advantage in reducing the environmental impact associated with higher density (smaller well spacing) development.

9. Within the industry, there appears to be very little disagreement that a successfully drilled and optimally operated horizontal well could significantly increase rates and reserves in comparison with vertical wells drilled in the same coal. Modeling work performed by several authors indicates an expected performance (rate and reserves) increase with horizontal wells in the range of two (2) to six (6) times that of a vertical well. These increases have not yet been consistently realized in the San Juan Basin CBM. Horizontal wells drilled within the last two years have so far shown folds of increase in rates very much consistent with these modeling and simulation forecasts. If these rates can be maintained, significant economic and environmental benefits can be achieved over a short period of time. However, as indicated above a number of technical problems, including wellbore stability and plugging due to coal fines migration will have to be remedied.

5.0 DISCUSSION

5.1 Literature review of horizontal and directional wells in coal

The focus of this literature review is to present historical progress and developments made on horizontal and directional drilling technology in coal with an emphasis on production rate and recovery of reserves. Detailed reference locations for literature cited in this review are provided following the report text. Two distinct applications for horizontal drilling in coal have been reported in the literature. In the mining industry, horizontal boreholes have been used extensively to degasify coal seams with a dual intent to capture gas for sales and to enhance mine safety. In the oil and gas industry, horizontal wells have been used less frequently to increase gas production from deep, un-minable coals and to reduce surface disturbance associated with mining operations. Considerable learning and experience acquired via horizontal borehole drilling in conventional mining operations have contributed significantly to the advancement of horizontal drilling technology in deep coal bed methane reservoirs.

Drilling horizontal segments from an existing vertical wellbore is not a new idea and, in fact, the first patent for equipment to place a horizontal drain hole from a vertical well was granted in 1891. The first truly lateral hole was drilled in 1929 in Texas and since then horizontal drilling technology has been improving in both performance and reliability.

Horizontal borehole drilling for coal seam degasification was implemented for the first time in the United States in 1958 (Thakur and Poundstone 1980). Nowadays, such a drilling activity usually occurs up to several years ahead of the actual mining activity due to improvements in directional control and economics. In addition to potentially producing a significant amount of methane over an extended period of time through these horizontal boreholes, mine safety has also been improved considerably by reducing methane emissions into mines.

In a paper published by Diamond et al. (1980), the authors describe the details of a pilot project in the Emerald Mine (near Waynesburg, Pa) aimed at improving directional drilling technology. Three long horizontal degasification holes were drilled in the coal from a directional borehole. Furthermore, a single vertical borehole was drilled for coalbed dewatering followed by seven additional vertical boreholes to monitor the progress and extent of degasification process with time. The project was able to demonstrate that the technique of directional drilling can be used to degasify coalbeds, and that reasonably long horizontal segments can be practically drilled in deeply buried coals. Drilling techniques developed in this pilot project have served as the basis for continuous improvement up to the present time.

A successful pilot project was also conducted in the Rocky Mountain area at the Soldier Canyon Mine of Carbon County, Utah (Schwoebel 1987). In this project, a total of 40 horizontal boreholes (over 65,000 feet of cumulative length) were drilled into a 16-foot thick coal seam at a depth of 2,000 feet. Pipeline quality gas was successfully collected via an underground pipeline network.

In a theoretical study by Ertekin and Sung (1986), the authors presented a paper focusing on the production aspects of horizontal drainage wells for coal seam degasification using a multidimensional coal bed methane simulator. The model permitted evaluation of multiple horizontal boreholes originating from a common vertical shaft. Several important coal seam parameters were identified and different horizontal borehole completion schemes were studied in order to better understand the various factors that play major roles in methane drainage process via horizontal boreholes. Sensitivity runs were performed by changing such parameters as borehole diameter, penetration length and positioning of the borehole. One important finding of this study was that the expected ultimate recovery from a horizontal borehole drilled in a coal seam can be maximized over the producing life of the well if the borehole is oriented orthogonal to the face cleat. If only one borehole is to be drilled, it was recommended that it be placed in the upper part of the coal seam. Drilling two parallel horizontal boreholes in a thick coal seam at different elevations was shown to increase the gas production rate drastically with an associated increase in water production rate. Production rate was further increased with increased vertical conductivity within the coal fracture network. In this study, several simulations were run using borehole lengths of 300, 500, 955 and 1,910 feet. Production rate was observed to increase with length. Furthermore, model results indicated that during an initial production period, gas production rate was higher for the boreholes drilled parallel to the face cleat, however, as the production continued, boreholes perpendicular to the face cleats became more powerful in transmitting methane to the wellbore and a cross over in production rates and ultimate recovery occurred.

In a paper published by Logan and Schwoebel (1987) on the application of horizontal drilling technology for coal seam gas recovery, the authors tried to justify the viability of such a drilling technique by arguing that due to low permeability, coal reservoirs usually require hydraulic fracture stimulation to achieve economic production levels. Hydraulic fractures in vertical wells usually propagate parallel to the maximum stress (or permeability) direction; therefore they may not adequately drain an anisotropic reservoir. A more effective stimulation technique, therefore, is a horizontal borehole placed perpendicular to the face cleat direction, thereby providing maximum access to the primary flow channels.

In this paper, the authors classified horizontal wells into four categories: (a) very short radius -- 1 to 2 feet (b) short radius -- 35 to 45 feet (c) medium radius -- 300 to 500 feet, and (d) directional -- 1800-2800 feet radius. In a project called “Deep Coal Seam Project”, they describe drilling and production results for 2 vertical and one short radius horizontal well in the Piceance Basin. The horizontal well was designed and drilled specifically to be placed perpendicular to the maximum permeability or face cleat direction. The paper provides a detailed account of operational issues when placing a short radius horizontal well in a coal seam. They also discuss the details of drilling technique, tools and wellbore stability issues, which they considered to be of primary importance. At the time the paper was published the horizontal well was undergoing initial testing and no further information on the performance was available.

In a later paper published by Logan (1988), the author discusses the application of a medium range horizontal well in the Rocky Mountain region. Similar to the previous paper, the technical details on the use of various types of equipment and drilling procedures are fully discussed. One conclusion reached in this study is that the short radius drilling technique lacks the accuracy needed for azimuth and inclination control whereas the medium-radius technique has the ability to place a long horizontal well on target.

In a paper published later by Deimbacher et al. (1992), the authors argue that in coalbed reservoirs, permeability is usually highly anisotropic, with the maximum permeability invariably along the maximum horizontal stress. Similar to Logan et al., they hypothesized that when a vertical well is hydraulically fractured, the fracture propagates parallel to the maximum permeability direction. However, this is highly undesirable from production standpoint when the bilinear flow concept would necessitate a large permeability normal to the fracture face. These authors used numerical simulation techniques to show that horizontal wells drilled in the orthogonal direction (i.e. normal to the maximum permeability and the main natural fissures) can provide significantly larger gas rates than equivalent vertical wells. Furthermore, several small hydraulic fractures placed in the horizontal well with proper zonal isolation can further increase the well productivity. The authors claim that considering the highly fissured, cleated nature of coalbeds, small stimulations in horizontal wellbores are far easier to perform than a single treatment in vertical wells.

Other conclusions reached in this study indicate that although length of the horizontal well is quite important in increasing production rate, its positioning is relatively unimportant in thin coal seams. Furthermore, horizontal permeability anisotropy plays a critical role in comparing the performance of a fractured vertical well with that of an unfractured horizontal well. The larger the anisotropy, the more attractive the horizontal well will be compared with the fractured vertical well. Horizontal wells are particularly suitable when the horizontal to vertical permeability ratio is small (i.e. good vertical communication, as in naturally fractured formations). The thinner the formation, the more it will favor a horizontal over a vertical well. For thin coal seams the vertical to horizontal permeability anisotropy is relatively unimportant, however, the anisotropy in the horizontal plane is far more critical. From the results of the simulations performed, the authors claim that a qualitative knowledge of the permeability anisotropy is essential before the well is drilled. Actual knowledge of the magnitude of such anisotropy is essential for proper design and sizing of the well. Furthermore, in comparing the fractured vs. non-fractured horizontal well and fractured vertical well, the paper reports that an unfractured horizontal well drilled normal to the larger permeability in a highly anisotropic formation would result in an increase in productivity index between 75% and 100% over both the longitudinally fractured horizontal well and the fractured vertical well.

Unrelated to coal reservoirs, the work published by Caldwell and Heather (1991) discusses horizontal drilling in the Austin Chalk formation (South Texas). The authors claim that the conclusions reached in their study are equally applicable to coal reservoirs due to similarities in fracture distribution between tight gas and coal formations. In the Austin Chalk, horizontal wells have enjoyed significant success in areas already considered depleted by vertical wells. Detailed analysis of the vertical wells in the area indicated two groups of wells with significantly different estimated ultimate recoveries (EUR's). The authors have attributed this difference to the communication, or lack of it, between the wellbore and the in-situ fracture swarms. Horizontal drilling has the effect of substantially improving not only the chance of encountering multiple fracture swarms but also several fracture swarms may be intersected in a single wellbore. The paper states that EUR'S for the horizontal wells in the study area averaged 119 MBO while the fracture stimulated vertical wells averaged 55 MBO.

The work by Sarkar and Rajtar (1994) further improved on horizontal well technology by developing type curves applicable to coal bed methane reservoirs for transient well testing. Through this type curve matching process, both reservoir and sorptive characteristics of coal can be quantified. The authors present an equation which they claim to be the most general pressure response equation for single phase flow in a semi-infinite CBM reservoir.

A paper by Osisanya and Schaffitzel (1996) brings to focus similar ideas expressed previously regarding the horizontal well drilling in coal. They state that the properties of a coal bed essential to its completion methodology are dual porosity, permeability, gas desorption, stratigraphy, bottomhole pressure, and water production. Vertical wells can not be economically justified without fracture stimulation, however, horizontal wells are considered to be very effective in reservoirs that are relatively thin, naturally fractured, and known to have anisotropic permeability which is the case in most coal reservoirs.

Permeability anisotropy, particularly in thin seams, plays an important role in the performance of horizontal wells. As found previously, the horizontal section of the wellbore must be drilled perpendicular to the face cleat, or the greatest permeability to achieve highest production rate possible. Prior to initiating a drilling program, several core samples should be tested to determine the minimum and maximum stress directions and to determine how weak and friable the coal is to ensure wellbore stability. The paper also discusses additional practical guidelines with regard to the drilling aspects of horizontal wellbores.

In comparing changes in well productivity, a US Bureau of Mines report has shown through simulation studies that a properly drilled and completed horizontal well can increase gas production by about 75% over that of a fractured vertical well (Ertekin and Sung 1986).

Chi and Yang (2000) discuss a conceptual methodology for drilling a network of horizontal wells in coal reservoirs. Two patterns of “net” and “twig” are described. In the former, multiple horizontal wells are drilled to form a square grid. The latter is made up of multiple horizontal wells in parallel where each well (main trunk) may contain multiple branches in forming the network. The author claims that these drilling patterns, although not practically verified yet, can be very promising for many low permeability, low pressure coal bed methane reservoirs in China which have not responded economically to vertical drilling.

A recent paper authored by Chaianansulcharit et al. (2001) reports on the impact of permeability anisotropy and pressure interference on CBM gas performance. Although the paper does not explicitly discuss the type of completion, it states that the most optimum drainage pattern for CBM field development is one of rectangular shape rather than a square shape. Determination of the optimum drainage aspect ratio and orientation, however, requires knowledge of the orientation and degree of in-situ permeability anisotropy. In the case of horizontal wells, the well productivity will be even more dependent upon pattern spacing, aspect ratio and permeability anisotropy.

A paper by Sams et al. (2002) describes a generic coal field sequestration/enhanced coal bed methane project using horizontal wells as producers and injectors. The authors argue that the increased rate and recovery by horizontal wells relative to vertical wells is due to better connectivity of the wellbore with reservoir rock (in this case coal). In this simulation study, the length of the injection lateral was varied between 300 and 1,000 feet while that of the producing wells was kept at 3,000 feet. Investigators found that the injector length can have a significant effect on the volume of carbon sequestered. In almost all cases studied, they found that the most optimum length of a horizontal well which yields maximum CO_2 sequestration is in the range of 300 to 600 feet (as opposed to 1,000 ft). An indirect conclusion from this study is that productivity of a horizontal producer (rather than an injector as shown in the paper) should be optimized by varying the length of the horizontal segment. This optimum length is strongly influenced by the reservoir and other operational parameters.

A paper by Jan et al. (2002) describes the development and testing of an improved coalbed reservoir simulator. A coalbed methane well in the fairway region of San Juan Basin was used for history matching as a test case (actual well name and location have not been provided). The well was originally a vertical well which had been producing for five years before being side tracked and converted to a horizontal well. The vertical well was fractured in the Fruitland upper and basal coal intervals. The horizontal section of the well was approximately 1,200 feet in length (open hole) and was producing from the Fruitland basal coal section. The horizontal section was fractured with an estimated fracture length of about 215 feet. When the well was simulated only as a vertical well, its cumulative gas production was predicted to be about $1/6^{th}$ of the actual recovery observed by the well after the addition of the horizontal side track.

5.2 Comparison of vertical, deviated and horizontal well performance in San Juan Basin

An important element of the current study involved developing a methodology whereby the production behavior of horizontal and deviated wells at different locations in San Juan Basin could be compared with vertical wells. Given the scope of the project the analysis needed to use readily available data and information to make basic performance comparisons. MHA adopted two different methods; the first approach examined maximum sustained rates over a one year period and estimated ultimate recovery (EUR) for each of the wells in the comparison database. The second method compared producing rates between the vertical and non-vertical wells over a common time frame. Each of these methods has technical shortcomings, but in the aggregate the comparisons are consistent and provide a meaningful summary of the success of horizontal or deviated well drilling in the San Juan Basin to-date.

Using the IHS Energy Database a query was made to identify all non-vertical wells completed in the Fruitland coal by selecting for the keyword “hole direction”, either “deviated” or “horizontal”. From a total of nearly 5100 wells, this search resulted in identifying 17 horizontal wells (TABLE 1) and 174 deviated wells in the Fruitland Coal (TABLE 2). Of the 17 horizontal wells, only five contained detailed directional survey information that specifies measured depth (MD), true vertical depth (TVD), drift angle and azimuth. Furthermore, of the 17 horizontal wells, seven have been drilled as new wells, while the rest are horizontal laterals drilled off of an existing vertical trunk. In analyzing the performance of these wells, as will be discussed later, the second of MHA’s analysis approaches considered only the time period after the horizontal section was drilled since IHS reports both the original and the horizontal re-drill production rates under the same API number. In the horizontal well group, the measured depth ranged from 2,809 to 8,539 feet with an average of 4,488 ft. The average reported TVD within this group was 3,470 ft. Hence, the average measured depth for the horizontal wells was 1,018 feet longer than the TVD average.

For the group of wells designated as “directional”, 46 out of 174 wells contained information on both MD and TVD. Of these, 22 wells contained details of directional survey. The measured depth of these wells varied between 746 and 7,410 feet with an average of 3,328 ft. The average reported TVD for this group was 3,098 feet and, hence, the measured depth for the directional wells was only 230 feet longer than TVD average as compared with 1,018 feet for horizontal wells. In this study, we identified the “highly deviated” wells as the 13 wells with a difference between MD and TVD greater than 300 ft. These 13 deviated wells are listed in **TABLE 3**.

To compare the performance of horizontal and directional wells with vertical wells on a common basis, MHA first identified the section land in which a particular horizontal or deviated well (using the reduced dataset of deviated wells in TABLE 3) has been drilled. A second search was subsequently performed to identify all other vertical wells located in the same section. (For one particular horizontal well, there were no vertical wells within the same section so wells from adjacent sections were selected.) The number of offset vertical wells for each non-vertical well ranged between one and five. TABLE 4 provides a list of all of the wells derived from these queries and represents the ‘comparison dataset’ of 101 wells.

MHA’s first comparison involved analyzing the production behavior of each well to determine the maximum sustained monthly producing rate, which was defined for this study as the maximum annual production divided by 12. In addition, MHA performed a decline curve analysis to project remaining gas production and thereby determine the EUR, which is equal to the cumulative production and the remaining reserves. (Appendix A shows a semilog rate versus time plot with the production forecast for each of the wells in the comparison dataset.) Based on observation of the production behavior for wells in this comparison dataset and experience in the San Juan Basin, a minimum effective annual decline of 10 percent was used. This decline rate was also applied in cases where there was not an established decline. This minimum decline was adopted because it imposed some consistency in the extrapolation of performance, and because it was not within the project scope off work to perform a detailed analysis of production performance that was not exhibiting an established decline. The exceptions to these decline curve analysis guidelines were CDX’s two recent wells, the Penrose 1R and Anderson 1R. Both wells consist of multilateral horizontal legs and exhibited significant rate increases through the second half of 2003. Both wells are reported to be producing currently at stabilized rates reflecting relatively low drawdowns. Therefore, reserves for the Penrose 1R and Anderson 1R were forecast assuming three years of production at constant rates equal to the rates as of November 2003, and then were forecast to decline at an average annual effective rate of 25 percent. These forecasts were based on the prospect that the wells would continue to produce at below-capacity rates in order to avoid drawdowns that might cause wellbore instability. Once the reservoir pressure reaches a point where the wells can produce safely against the line pressure the decline rates will be larger than those of vertical wells because the reservoir will be depleting more rapidly to a lower abandonment pressure. Clearly, with the limited production history and the assumptions inherent in their forecasts, the reserves for these newer CDX wells have a larger than normal uncertainty in their estimate.

TABLE 5 is a detailed summary of the maximum rates and EURs for the comparison data set. Since the wells are distributed throughout the San Juan Basin, **TABLE 5** indicates that there is a wide variation in the results, with maximum rates ranging from less than economic rates of about 300 MCF per month to as much as 310,000 MCF per month, and EURs varying from less than 10 MMCF to more than 27,000 MMCF. A relative performance index was determined by taking the ratio of the maximum rate and EUR for horizontal or deviated well within a particular section to the average maximum rate and EUR for the offsetting vertical wells. The ratios of the rates and EURs were equally weighted to derive the so-called performance index (see equation in Note on **TABLES 6 and 7**).

TABLE 6 shows the resulting performance index comparisons for the horizontal wells and indicates that they range from complete failures (a performance index of zero) to highly successful (as indicated by a performance index of 7.5). The average performance index is 1.6, which indicates that in the aggregate the EUR and maximum annual rate of the horizontal well is 1.6 times that of the offsetting vertical well(s). It is important to note, however, that the very recent performance of the two CDX wells, the Penrose 1R and Anderson 1R, which have performance indices of 7.5 and 2.2, respectively, significantly influence this average. Excluding these two well, the average performance index is 1.1. This is important to understand because these two wells have very little production history upon which to base a maximum annual rate and EUR. **TABLE 7** shows the results of the performance index analysis for the deviated wells and indicates that the outcome ranges from failure (performance index of 0.1) to some improvement (performance index of 1.4). However, the average deviated well with a performance index of 0.8 has exhibited a lower maximum annual rate and is expected to recovery less gas than the offsetting vertical wells. These comparisons can be visualized by inspection of the plots in Appendix B, which show for each of the comparison well sections semilog plots of gas rate versus time for the horizontal or deviated well and the offsetting vertical wells. The first of these plots for each section shows the data in 'real time' (as the wells were drilled and produced) and in 'normalized time' (where each well begins producing from the same time zero).

The variation in performance for the horizontal and deviated wells is illustrated in **FIGURES 1 through 4**, which show the production performance for the horizontal wells in the Colorado and New Mexico portions of the San Juan Basin, respectively (**FIGURES 1 and 2**), and the performance of the deviated wells in the same geographic divisions (**FIGURES 3 and 4**). As indicated earlier, some of the horizontal wells were originally vertical wells (**TABLE 1** indicates the completion dates of the horizontal well segments). While this condition would influence the performance index comparison described above, incorporating its influence in this analysis would not change the general conclusions reached. In other words, horizontal drilling has generally produced wells that exhibit higher rates and reserves than offset vertical wells, but there is a wide variation in horizontal well performance and the average horizontal well performance does not represent an improvement over a vertical well commensurate with the increased drilling costs.

MHA's second performance comparison consisted of calculating the average rate for the offsetting vertical wells over the same time interval as the producing period of the horizontal or deviated well. Appendices C and D contains plots of rate vs. time showing for each horizontal (Appendix C) and deviated (Appendix D) well the relevant time and rate comparison. TABLES 7 and 8 compare the average rate between the horizontal and deviated wells, respectively, and their offsetting vertical wells. TABLE 7 indicates that in approximately 70% of cases, the horizontal wells performed poorer than the offset vertical wells by an average of 470 MCFD. For the remaining 30% of the cases where the horizontal wells did better than the offset vertical wells, the average rate increase was about 1125 MCFD. Analyzing the data using average rate ratio instead of rate difference, it was found that the ratio of horizontal well average rate to that of offset vertical well varied between 0.1 and 5.1 with a mean of 1.3. TABLE 8 shows that in the case of deviated wells about 40% of these wells did better than the offset vertical wells with an average rate increase of 350 MCFD. For the other 60% where deviated wells performed worse than the vertical offsets, the reduction in rate averaged at about the same level of 350 MCFD. The average rate ratio of deviated to offset vertical wells showed a range of 0.2 to 1.5 with a mean of 0.9.

5.3 Feedback from Operators

In an effort to capture the opinion and current position of San Juan Basin operators concerning horizontal or deviated wells, MHA interviewed representatives of several companies, getting input from technical and management staff. The level of cooperation in providing detailed information ranged from none to substantial. A summary of such discussions is presented below.

Within the past two years, six horizontal CBM wells have been drilled in the San Juan Basin by two companies, CDX Gas and Williams Production Company. CDX drilled two wells offsetting Petrox's Tiffany Field, and Williams drilled four wells in New Mexico. As discussed below, the companies' have very different approaches and associated costs.

CDX Gas has acquired multiple patents for developing a new horizontal drilling and completion system known as the Z-Pinnate process. The method is intended to maximize gas production rate and ultimate recovery from coal seams in less time and with less environmental impact than traditional drilling methods. The company claims that this process can drain up to 1200-acres from a single drill pad. To develop an equivalent area with conventional vertical drilling would require 16 well sites (New Technology Magazine: Oct/Nov 2003). Furthermore, even in low-permeability coal bed formations, CDX claims that its Z-Pinnate horizontal drilling and completion system can recover

80% to 90% of the methane in-place, compared to just 10% to 70% using conventional technology.

CDX has not yet applied the specific Z-Pinnate drilling technology in the San Juan Basin, but to test the concept of improved multilateral drilling, CDX has drilled two multilateral horizontal wells in the San Juan Basin Fruitland coal formation. In both cases, the casing in the vertical section was milled across the coal interval and the hole was under-reamed or cavitated. The horizontal sections intersect the vertical section in the milled and under-reamed area and then extend out one-half to two-thirds of a mile. Based on available information, it is not clear if both wells have employed the same multilateral configuration, but it is believed that the surface locations are basically near the center of a quarter-section with the laterals extending into the center of the adjacent quarter-sections, thereby developing a spacing unit of between 320 and 640 acres.

The first well, Anderson #1R, was drilled in Section 5-32N-6W, La Plata County, Colorado, without fracture stimulation at a cost of $1.3 million ($MM). (This cost is approximately 4 times the typical drill and complete costs of the average $320,000 for wells on the Colorado side of San Juan Basin.) The laterals have a total horizontal length of 9,000 feet and were designed to drain a minimum of 320 acres in an area where existing vertical wells have an average production rate between 100-200 MCFD. The targeted coal has an average thickness of 12 feet. Initial production rate for this well was measured at 1.2 MMCFD against a relatively high wellhead flowing pressure of 700 - 800 psi, and a flowing bottomhole pressure in excess of 1000 psi. Shortly after production, the well experienced problems due to coal fine migration into the wellbore. However, after expensive clean up and liner installation the production rate once again increased to 1.6 MMCFD at the same wellhead and bottomhole flowing pressure conditions. However, in order to mitigate the plugging problem associated with fine migration, the well was choked back to a rate of between 600 and 700 MCFD for the latter part of 2003 and has subsequently been without any apparent production problems. The average daily gas production rate for this well (API# 05-067-08746), as shown in Appendix C, appears to be much higher than the average of vertical offset wells within the same section. In summary, while the well does show increased productivity, the primary benefit of increased flow rate from the horizontal laterals has been somewhat mitigated by the need to operate the well below its ultimate production potential in order to prevent fines migration and costly future cleanup.

The second well, the Penrose 1R located in La Plata County, Colorado, is an offset to Anderson 1R in Section 8-32N-6W and initially produced at a choked-back rate of 1.3 MMCFD from a 10-ft coal seam. Due to experience with coal fine problems observed earlier, a production liner was installed from the beginning. Total drainage area of this well is estimated to be around 240 acres as some of the coal seams begin to thin out around the edges of the section. The well has a ‘pitchfork’ type of multilateral system with three horizontal laterals extending more or less in the same direction but 650 feet apart from one another. It is unclear whether there are one or two sets of these ‘pitchfork’ multilateral sets of wellbores; if the intent is to drain 640 acres, it is likely that there are two such sets of multilaterals but this could not be confirmed with information available in the public domain. Again, the total drilling and completion cost of this well was reportedly about $1.3MM. After producing for about two months at the rate mentioned above, this well also experienced severe plugging problems due to coal fine migration and was cleaned out once with coiled tubing. At some point during (or shortly after) a two week shut-in for construction and maintenance of the sales line, the laterals apparently collapsed. After three and a half months of workover production was restored and CDX has slowly opened the well, increasing the rate to about 2.2 MMCFD in November 2003. Although both the Anderson and Penrose wells are flowing into a line pressure of around 100 psi, the wells are believed to be choked back to flowing tubing pressures of approximately 400 psi. CDX Gas has selected two additional sites to drill similar wells in the San Juan Basin, each with a drainage area in the range of 480 to 640 acres.

CDX has recently drilled a third horizontal well in New Mexico near the HD Mountains. The well has a total vertical and horizontal length of 8,000 ft overlaying a 320 acre spacing unit. This well, however, has not performed nearly as well as the previous two wells described above. CDX speculates that this well may be suffering from liquid loading in the horizontal section as some of the CBM wells in this area produce up to one barrel of liquid hydrocarbon per day. Currently this well is producing at a rate of 50 MCFD. It is interesting to note that a conventional horizontal well drilled in the same section and operated by Conoco-Phillips is currently producing at about 200 MCFD from a 1,500 ft horizontal section.

In summary, although the increase in gas production rate for the CDX wells compared to offsetting vertical wells is substantial, remedial operations following drilling have been expensive and it is likely that additional sustained production will be required to confirm that CDX's technology has significant and widespread application in the San Juan Basin. Certainly, recent performance data indicates that both the Anderson and Penrose wells have been operating in a stable manner with rates approaching their initially designed targets. This is certainly encouraging if such a novel technique should find widespread acceptance by other operators for recovering significant volume of gas from environmentally sensitive areas of the San Juan Basin. One area of remaining uncertainty is that at this point in time it is not known how these types of wells will perform in areas of higher coal permeability where conventional vertical wells have been shown to adequately drain larger areas at high rate by targeting multiple coal seams.

Although Williams Production Company declined to provide direct input to this report, information obtained from other sources indicates that its horizontal drilling technique is 'conventional' and therefore simpler and less risky than that used by CDX. William's application involves drilling a single lateral 1,000 to 1,500 feet in length that is cased with a 4.5" slotted liner. The company drilled 4 wells in 2003, one collapsed but the other three wells are currently producing at rates of 280, 500 and 600 MCFD. Williams claims that its wells take less time to drill than conventional coal wells with cavitation, and that it takes between seven and 10 days to construct a well and its horizontal leg. The well cost is in the range of $600,000 to $800,000 which is the same as a conventional well with cavitation. An additional five to seven wells are planned for 2004 using locations that are close to ¼ section lines and utilizing existing pads to avoid new road construction and surface impacts.

BP America provided valuable input with regard to its experience in both horizontal and directional drilling in the San Juan Basin. Currently, BP views this technology as still maturing; encouraging and having some good results but also having plenty of documented failures. In it's view, the well performance in the context of the risk of mechanical failures and costly repairs and does not compare favorably with the higher drilling costs.

BP believes that there are a number of technical challenges facing horizontal drilling in coal. The most important one is wellbore stability. In the horizontal section, the hole can potentially come in contact with large fractures in a low stress environment, resulting in coal collapse and the loss of the hole. A second important problem, as CDX has experienced, is keeping the hole clear of coal fines which are difficult, time consuming and expensive to remedy, particularly in the horizontal section of the well. In vertical wells, this problem is generally remedied by installing a perforated liner along the coal face. In a long horizontal well, however, it would be very difficult and quite challenging to install such a liner over the entire horizontal section. Furthermore, even if a liner can be installed partially into the horizontal section, at some point into the life of the well the hole needs to be cleaned out and the technology for doing the cleanup for a long, horizontal liner has not yet been fully developed. A third potential problem for horizontal wells in areas with high water and/or moderate liquid hydrocarbon production is unloading the well (i.e. removing the accumulated liquids from the bottom of the well). Dewatering the coal is the primary mechanism for gas desorption from the internal surfaces of the coal. For wells with moderate water production, downhole electric pumps can be used to pump the water through the horizontal section and into the primary wellbore. However, the use of rod pump and issues related to moving the equipment through the vertical bend poses serious challenges given the current state of technology.

Another challenge facing the operators is finding areas where reservoir rock properties and geologic settings are favorable for horizontal drilling. For instance, in the fairway region of San Juan Basin (New Mexico) where the coals are more permeable and have higher fracture density, the stress environment is such that horizontal wells have a higher probability of experiencing mechanical failure than in the tighter regions further north in Colorado. However, these northern regions have historically been producing at a much lower rate than the Fairway wells, which brings into focus the issue of risk and potential reward in horizontal drilling. In addition, horizontal wells can be drilled more economically if the majority of the gas is stored in a single, thick coal seam with significant lateral continuity. The eastern portion of the Northern San Juan Basin EIS study has lower permeability, but relatively thick coal in two distinct coal intervals. The western portion of the area, however, has very different geological characteristics from the eastern area and is characterized by multiple distinct coal seams. BP has provided a set of cross sections (see Appendix E) highlighting variability in coal seam distribution and lateral coal across the basin. The impact of reservoir geology on the long term performance of horizontal wells in San Juan coal has not yet been fully evaluated.

BP also provided valuable comments with regard to drilling, completion and production of directional coal wells in the San Juan Basin. The company is currently utilizing directional drilling to the extent possible for downsizing to 160 acre spacing in its infill drilling project. Based on BP's comments, it appears that wells with deviation angle greater than 30 degrees face more difficult technical challenges than those drilled at less than 30 degrees. In this case, the deviation angle is dependent upon the distance measured from the center of a quarter section (bottom hole location of infill well) to the new well surface location, or to an existing drill pad. For instance, a deviated well drilled at the center of a quarter section will require an average deviation angle of 45-50 degrees versus 25-30 degrees if the well is drilled offset to the center by 700 ft.

As part of their infill drilling program, BP has drilled 10 deviated wells within a year where the majority of wells have deviation angle in the range of 25-30 degrees. Only one well has a deviation angle exceeding 45 degrees. No major difficulty was encountered in the drilling process relative to conventional vertical wells, even for the highest angle well. However, areas where significant technical challenges remain to be addressed are in completion and production optimization. Fracture stimulation appears to be problematic for the higher angle wells but not so much for the low angle wells. Although there appears to be good control in executing the fracture treatments for even the most deviated well, well performance suffers (in relative terms and in comparison with vertical wells subject to similar fracture treatments) as the deviation angle increases. It is not clear at this time why a highly deviated well can not be as effectively stimulated as a regular vertical well. Some speculation as to the cause can be made in the way hydraulic fractures connect with the natural fracture system in the coal. To compensate for the less effective fracture stimulation and higher gravitational effect, wells with deviation angle exceeding 30 degrees appear to have an increased need for artificial lift compare to nearby vertical wells. Removing water from a slanted well requires additional energy as compared to a vertical well having the same depth. Alternatively, without such artificial lift, the well has to produce at somewhat higher rate to compensate for the negative effect of gravity.

From a financial point of view, BP believes at this point in time that the savings realized by the use of an existing pad for drilling a deviated well may be compromised by the additional costs for artificial lift, and by the lower production rate due to less efficient fracture stimulation. This has a negative impact on the economics of high angle wells. Furthermore, particularly for highly deviated coal wells, BP's limited experience indicates that these wells may require longer time to stabilize after they come on production due to longer clean-up time (as high as one year) as compared to less deviated wells (< 25-30 degrees) and/or vertical wells (with cleanup times of three months or less). The company is currently analyzing the performance of these newly drilled deviated wells while evaluating alternative fracture stimulation and production optimization techniques. If some of the above-mentioned technological challenges can be resolved successfully, the cost saving and the reduced environmental impact on the surface will make deviated well drilling a potential alternative to vertical drilling for the ongoing basin-wide infill drilling program. However, BP believes that it may take another year to fully evaluate the performance of the deviated wells.

Another company which provided information for this report was Petrox Resources Inc. (Petrox). Petrox is one of the companies proposing selective horizontal drilling in the eastern portion of the EIS study area in Archuleta County; however, it has expressed concern that at the present time a large scale horizontal drilling project in the Basin will have a difficult time attracting pipeline companies to invest in surface infrastructure as they perceive this technology as having too much uncertainty, which compromises production forecasts. Petrox estimates four to five horizontal wells with single laterals will be required to drain a section effectively. They plan to monitor the performance and use history match models to predict long-term production. The company anticipates at least three to five years for gathering data and solving operational problems associated with horizontal drilling. An alternative approach Petrox is considering is to initially drill conventional vertical wells (downsizing from 320 to 160) using a larger casing (larger than 9-5/8 inch) so that horizontal segment can be added at a later time. This can be accomplished by setting a whipstock over the coal section and drilling laterally into the coal. Alternatively, a pre-milled window system can be used to drill a short radius horizontal wellbore into a coal seam, although at a significantly higher cost that may be prohibitive at this time.

Petrox believes that for small operators with limited drilling budgets, a primary concern with implementing horizontal well technology is securing financing from commercial banks since horizontal drilling in the San Juan Basin is viewed as a relatively high risk investment with limited performance and reliability history. Higher drilling and maintenance cost as compared to conventional vertical wells are also considered by small operators to be an impediment in pursuing this technology due to their limited financial strength.

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TABLES

Horizontal Wells Derived from HIS Database
San Juan Basin, Fruitland Coal

API	LEASE	OPERATOR	LOCATION	STATE	COUNTY	Completion Date Vertical Well	Horizontal Well Cum (MMCF)	Completion Date Horizontal Well
05067070610000	SO UTE J-26 #1	BP AMERICA PRODUCTION CO	26 33N 11W SE NW SE	CO	LA PLATA	Aug-88	5,123	Aug-98
05067071460000	SHORT ALVA GU A #1	BP AMERICA PRODUCTION CO	7 33N 9W NW SE SE	CO	LA PLATA	Mar-91	3,915	Mar-00
05067072910000	SO UTE 32-9 #12-1H	BP AMERICA PRODUCTION CO	12 32N 9W SW NE SW	CO	LA PLATA	Feb-90	2,250	Aug-91
05067076220000	UTE 32-11 #402H	BURLINGTON RESOURCES O&G	4 32N 11W NW SE NE	CO	LA PLATA	Jun-93	11,518	Apr-98
05067086980000	PENROSE #1R	CDX GAS LLC	8 32N 6W NE SW SW	CO	LA PLATA	Jun-02	320	Jun-02
05067087460000	ANDERSON	CDX GAS LLC	5 32N 6W NE SW SW	CO	LA PLATA	Nov-02	156	Nov-02
30039242680000	SAN JUAN 32 5 UNIT NP	ENERGEN RESOURCES CORPOR	23K 32N 6W SW NE SW	NM	RIO ARRIBA	Mar-89	221	Mar-89
30039243480000	CARRACAS UNIT 34 B	ENERGEN RESOURCES CORPOR	34I 32N 4W SW NE SE	NM	RIO ARRIBA	Dec-90	167	Dec-90
30039244920000	SAN JUAN 30 6 UNIT	BURLINGTON RESOURCES O&G	28M 30N 6W NE SW SW	NM	RIO ARRIBA	Mar-90	19,113	Apr-98
30039246000000	SAN JUAN 30 6 UNIT	BURLINGTON RESOURCES O&G	29K 30N 6W SW NE SW	NM	RIO ARRIBA	Jun-90	14,323	Apr-98
30039248630000	ROSA UNIT	WILLIAMS PRODUCTION COMP	26E 31N 4W NW SE SW	NM	RIO ARRIBA	Aug-93	191	Aug-02
30039272390000	ROSA UNIT	WILLIAMS PRODUCTION COMP	13E 31N 5W NW SE SW	NM	RIO ARRIBA	Sep-02	115	Sep-02
30045268040100	PAYNE	BURLINGTON RESOURCES O&G	27 32N 10W NW NE NE	NM	SAN JUAN	Sep-96	3,717	Sep-96
30045272210000	SUNRAY H	BURLINGTON RESOURCES O&G	11 30N 10W W2 SW SW	NM	SAN JUAN	Apr-89	180	Apr-89
30045278310000	FC FEDERAL COM	CONOCOPHILLIPS COMPANY	18K 32N 11W SW NE SW	NM	SAN JUAN	Feb-92	407	Mar-96
30045289950000	HUGHES B	CONOCOPHILLIPS COMPANY	21A 29N 8W SW NE NE	NM	SAN JUAN	Sep-94	491	Sep-94
30045292050001	FLORANCE H	BP AMERICA PRODUCTION CO	6O 30N 8W SE SW SE	NM	SAN JUAN	Apr-95	14	Jun-03

Table 1

Deviated Wells Derived From HIS Database

API	Lease Name	Well Num	Operator Name	Location	State	County Name	Driller TD	Proj Depth
05067082020000	HUBER-LALONDE	4-31	HUBER J M CORP	31 35N 8W NW SW NE	CO	LA PLATA	2440	3000
05067074390100	SOUTHERN UTE FC 34-10	23-1	RED WILLOW PROD CO	23 34N 10W NW SE SE	CO	LA PLATA	2810	2800
05067079600000	FLOREINE HUDSPETH G U `A`	1	AMOCO PROD CO	12 34N 7W SE SE NW	CO	LA PLATA	2340	2180
05067066060100	SOUTHERN UTE	20-2;33-10	VASTAR RESOURCES INC	20 33N 10W NW SE SW	CO	LA PLATA	3476	
05067065240100	DAVIS GAS UNIT	1	SG INTEREST I LTD	4 33N 10W SW NE NW	CO	LA PLATA	2903	2885
05067071280100	ORAN SHORT A	1	AMOCO PROD CO	8 33N 9W SW NE SE	CO	LA PLATA	2650	2650
05067074420001	SOUTHERN UTE FC 34-10	25-2	RED WILLOW PROD CO	25 34N 10W SW NE NW	CO	LA PLATA	2623	
05067082330000	HUBER-RHODES	4-33	HUBER J M CORP	33 35N 8W NW NE SE	CO	LA PLATA	2482	3000
05067081780000	BLACK RIDGE	SU17-4	ENERVEST SAN JUAN	17 33N 10W NE SE NW	CO	LA PLATA	4538	
05067064500100	PARSONS	8-1	SG INTEREST I LTD	8 33N 10W SW NE NE	CO	LA PLATA	3027	
05067072840100	SOUTHERN UTE 32-8	16-3	VASTAR RESOURCES INC	16 32N 8W NW NE NE	CO	LA PLATA	3880	3880
05067081590000	TENORIO	3-32	HUBER J M CORP	32 35N 8W SE NW SE	CO	LA PLATA	2143	3000
05067069780200	SOUTHERN UTE	22-2	44 CANYON LLC	22 33N 11W N2 NW NE	CO	LA PLATA		3413
05067074620100	KOON RAYMOND GU A	1	AMOCO PROD CO	19 33N 9W NE NW SE	CO	LA PLATA	2840	2840
05067072830100	SOUTHERN UTE	27-1	AMOCO PROD CO	27 33N 11W NE SW SE	CO	LA PLATA	3240	3240
05067081770000	BLACK RIDGE	SU8-3	ENERVEST SAN JUAN	8 33N 10W NW SW SW	CO	LA PLATA	4027	
05067082860000	MCCAW GAS UNIT D	2	AMOCO PROD CO	29 34N 8W SE SE SW	CO	LA PLATA	3320	3318
05067070490100	MCCULLOCH	28-1	SG INTEREST I LTD	28 34N 10W NE SW SE	CO	LA PLATA	3190	3200
05067071290100	ALVA SHORT GAS UNIT B/PLA-6/	1	AMOCO PROD CO	18 33N 9W NW SE NW	CO	LA PLATA	2890	2890
05067077220100	JACQUEZ THOMAS GAS UNIT G	1	AMOCO PROD CO	10 33N 10W SE NE NW	CO	LA PLATA	2870	2870
05067077980100	HUBER-JOHNSON	1-33	HUBER J M CORP	33 35N 8W SW SE NW	CO	LA PLATA	1950	2500
05067064130100	UTE `E`	4	SG INTEREST I LTD	9 33N 10W NW SE SW	CO	LA PLATA	3010	3010
05067087570000	SOUTHERN UTE TRIBAL EE	2	AMOCO PROD CO	31 34N 8W NE SE NW	CO	LA PLATA	3385	3467
05067064140100	UTE `E`	3	FOUR STAR O&G COMP	9 33N 10W NE SW NE	CO	LA PLATA	2900	
05067074350100	MCCULLOCH	29-3	S G INTERESTS I LTD	29 34N 10W SE NW	CO	LA PLATA	3700	3630
05067079040100	SOUTHERN UTE	20	FOUR STAR O&G COMP	34 33N 9W SE NW NE	CO	LA PLATA	6125	3460
05067082120000	SOUTHERN UTE FC 33-10	7-4	RED WILLOW PROD CO	7 33N 10W NE SE NW	CO	LA PLATA	4358	4322
05067063680100	UTE 34-10	1	SG INTEREST I LTD	33 34N 10W SW NE SE	CO	LA PLATA	3052	3053
05067064420100	ARGENTA UTE	3	SG INTEREST I LTD	31 34N 10W SE NW SE	CO	LA PLATA	3336	3328
05067071210100	SOUTHERN UTE 32-11	10-3	RED WILLOW PROD CO	10 32N 11W NE SW SW	CO	LA PLATA	2756	2700
05067072810100	SOUTHERN UTE FC 34-9	30-4	RED WILLOW PROD CO	30 34N 9W NW SE NW	CO	LA PLATA	2850	2850
05067072500100	MCCULLOCH 34-10	27-1	SG INTERESTS I INC	27 34N 10W SE NW SE	CO	LA PLATA	3035	3170
05067071320100	SOUTHERN UTE	21-1	CANYON CO THE	21 33N 11W W2 NE NW	CO	LA PLATA	2600	2608
05067069240100	JUDGE SIMPSON	1	CEDAR RIDGE LLC	18 33N 10W SW NE NW	CO	LA PLATA	4229	4015
05067078840100	SOUTHERN UTE FC 32-11	8-1	RED WILLOW PROD CO	8 32N 11W SW NE NE	CO	LA PLATA	2691	2800
05067069950100	SOUTHERN UTE FC 32-10	1-3	RED WILLOW PROD CO	1 32N 10W NE SW NW	CO	LA PLATA	2800	2787
05067071490100	SO UTE FC 34-9	31-1	RED WILLOW PROD CO	31 34N 9W SW NW SE	CO	LA PLATA	2905	2926
05067061500100	ARGENTA UTE	5	SG INTEREST I LTD	6 33N 10W NE NW SE	CO	LA PLATA	3444	3441
05067081580000	RHOADES	3-33	HUBER J M CORP	33 35N 8W NW SW SW	CO	LA PLATA	2295	3000
05067074430100	SOUTHERN UTE FC 34-10	1-26	RED WILLOW PROD CO	26 34N 10W NW SE NW	CO	LA PLATA	2866	
05067072690100	ALLISON DAVE	1	CEDAR RIDGE LLC	7 33N 10W NW SE SE	CO	LA PLATA	4516	4015
05067075950100	HUNGERFORD GAS UNIT A PLA-6	1	AMOCO PROD CO	6 33N 9W SE NW NW	CO	LA PLATA	2730	2890
05067081760000	BLACK RIDGE	SU17-3	ENERVEST SAN JUAN	17 33N 10W NE SE NW	CO	LA PLATA	4953	4953
05067077930000	BLACK RIDGE	SU17-1	BOWEN/EDWRD ASSOC	17 33N 10W NE SE SE	CO	LA PLATA	3250	3310
05067072510100	MCCULLOCH 34-10	29-2	SG INTEREST I LTD	29 34N 10W SW NE SE	CO	LA PLATA	3422	3432
05067074190000	LINDNER GAS UNIT A	1	AMOCO PROD CO	15 34N 9W SE SE NW	CO	LA PLATA	2720	2790
05067075270000	MCCAW GAS UNIT D	1	AMOCO PROD CO	29 34N 8W SE NW NW	CO	LA PLATA	3200	3161
05067075700000	LELAND HILL GAS UNIT A	1	AMOCO PROD CO	13 34N 9W NE NW SW	CO	LA PLATA	2975	2923
05067075830100	UTE 32-11	101	BURLNGTN RE OG CO LP	1 32N 11W SE NW NE	CO	LA PLATA	2977	2977
05067075860100	UTE 32-11	202	BURLNGTN RE OG CO LP	20 32N 11W SW NE NE	CO	LA PLATA	2578	2600
05067076800000	SOUTHERN UTE	5-13	AMAX OIL & GAS INC	13 32N 12W NE SE NE	CO	LA PLATA	746	800
05067077460000	BRIDGE TIMBER ISGAR	36-2	EMERALD GAS OPER	36 34N 11W SW NE NW	CO	LA PLATA	2715	2550
05067087410000	ANIMAS-UNIVERSITY WEST	9-3	TEXACO EXPL&PROD INC	9 34N 9W NE SE SW	CO	LA PLATA	2540	2945
05067077770100	MOSKETTI	43-33	MARKWEST ENERGY	33 34N 8W NW NE SE	CO	LA PLATA	3100	3135
05067087350000	KOSHAK	A-3	CHEVRON U S A INC	8 34N 9W SW NW SE	CO	LA PLATA	2694	2794
05067078160000	HUBER-BURKETT	2-24	HUBER J M CORP	24 35N 8W NE SE SE	CO	LA PLATA	2305	2200
05067078640000	WEST ANIMAS-UNIVERSITY	9-2	EMERALD GAS OPER	9 34N 9W NW SW	CO	LA PLATA	2405	2325
05067079270000	STATE GAS COM CF	1	AMOCO PROD CO	16 34N 7W SW NW	CO	LA PLATA	2584	2483
05067080560000	PARGIN	1-36	MARKWEST RES INCORP	36 33N 7W SE SE	CO	LA PLATA	2876	2775
05067063850100	SOUTHERN UTE 32-9	14-2	VASTAR RESOURCES INC	14 32N 9W SE NW NW	CO	LA PLATA	3386	3386
05067063960100	SOUTHERN UTE	19-1;33-10	VASTAR RESOURCES INC	19 33N 10W NW SE NE	CO	LA PLATA	3655	6527
05067064610100	SOUTHERN UTE	19-2;33-10	VASTAR RESOURCES INC	19 33N 10W NE SW SW	CO	LA PLATA	3420	6240
05067064780100	SOUTHERN UTE	18-1;33-10	VASTAR RESOURCES INC	18 33N 10W NW SE SW	CO	LA PLATA	3972	
05067067540100	SOUTHERN UTE	16-1;32-9	VASTAR RESOURCES INC	16 32N 9W NW SE SE	CO	LA PLATA	3280	8010
05067077490000	SOUTHERN UTE 32-9	6-2	ARCO OIL & GAS CORP	6 32N 9W NW SW SE	CO	LA PLATA	3305	3238
05067065190100	SOUTHERN UTE FC 34-9	30-7	RED WILLOW PROD CO	30 34N 9W SE NW NE	CO	LA PLATA	2909	2770
05067072240100	SOUTHERN UTE 33-10	1-3	RED WILLOW PROD CO	1 33N 10W NW SE NW	CO	LA PLATA	2618	2550
05067083340000	ANNALA ROY GAS UNIT A	2	AMOCO PROD CO	16 34N 8W NE	CO	LA PLATA	2540	2250
05067072870100	SOUTHERN UTE 33-10	24-3	VASTAR RESOURCES INC	24 33N 10W SW NE NW	CO	LA PLATA	2605	2605
05067083540000	SOUTHERN UTE 33-9	29-4	VASTAR RESOURCES INC	29 33N 9W SE SW NW	CO	LA PLATA	3601	3702

Table 2

Deviated Wells Derived From HIS Database

API	Lease Name	Well Num	Operator Name	Location	State	County Name	Driller TD	Proj Depth
05067084220000	WEASELSKIN GAS UNIT	2	AMOCO PROD CO	19 34N 9W SE SE NE	CO	LA PLATA	2928	2965
05067064390100	MCCULLOCH	1	SG INTEREST I LTD	34 34N 10W SE NW SW	CO	LA PLATA	2951	2950
05067084900000	ARGENTA 3	2	TEXACO EXPL&PROD INC	3 33N 10W SW NW NE	CO	LA PLATA	3478	2965
05067084810000	DAVIS FR	1A	ELM RIDGE RES INC	26 33N 9W SW NE NE	CO	LA PLATA	3618	3410
05067076490100	MCCULLOCH 34-10	28-2	RED WILLOW PROD CO	28 34N 10W NW SE NW	CO	LA PLATA	3283	3221
05067086520000	ISGAR A	4	TEXACO EXPL&PROD INC	18 34N 9W NE	CO	LA PLATA	2654	2307
05067086850000	SUNDANCE GAS UNIT	1	AMOCO PROD CO	8 34N 8W NE NW SE	CO	LA PLATA	2822	2839
05067086860000	SUNDANCE GAS UNIT	2	BP AMERICA PRODTN CO	8 34N 8W NE NW SE	CO	LA PLATA	2906	2925
05067087110000	QUINTANA 32-6	15-1	ENERGEN RES CORP	15 32N 6W SW SE NE	CO	LA PLATA	2808	2800
05067087340000	ANIMAS-CARTER WEST	7U4	TEXACO EXPL&PROD INC	7 34N 9W SE NE NE	CO	LA PLATA	2547	2845
05067087360000	KOSHAK	B-4A	TEXACO EXPL&PROD INC	8 34N 9W NE SE NW	CO	LA PLATA	2570	3058
05067084130000	HILL LELAND GAS UNIT A	2	AMOCO PROD CO	13 34N 9W NE NW SW	CO	LA PLATA	3250	3357
30039250160000	NORTHEAST BLANCO UNIT	423R	BLACKWOOD&NICHLS CO	8 30N 7W NE NW SE	NM	RIO ARRIBA	3705	3802
30045313630000	BLANCO NORTHEAST UNIT	464A	DEVON ENERGY PROD	10 31N 7W NW SE SE	NM	SAN JUAN	3558	3415
30045302000000	ROSA UNIT	341	WILLIAMS PROD CO	17 31N 6W NE NE SE	NM	SAN JUAN	3588	3290
30045288460000	HOWELL C COM	300R	MERIDIAN OIL INC	7 30N 8W NE NE NE	NM	SAN JUAN	2960	2786
30045282220000	NORTHEAST BLANCO UNIT	461	BLACKWOOD&NICHLS CO	12 30N 8W SW NE SE	NM	SAN JUAN	3850	3936
30045279410000	FIELDS A	22	AMOCO PROD CO	29 32N 11W NW SW NE	NM	SAN JUAN	3476	3468
30039253150000	NORTHEAST BLANCO UNIT	479R	BLACKWOOD&NICHLS CO	20 30N 7W SE NE NW	NM	RIO ARRIBA	4034	4131
30039073670101	SAN JUAN 28-7 UNIT	32	CONOCO INCORPORATED	19 28N 7W SE NW SW	NM	RIO ARRIBA	5580	5580
30039243930100	ROSA UNIT	202	WILLIAMS PROD CO	23 31N 6W NW SE SW	NM	RIO ARRIBA	3061	3061
05067067980100	SOUTHERN UTE TRIBAL E	1	AMOCO PROD CO	21 33N 7W SE NW SE	CO	LA PLATA	2436	2436
30039250090100	SAN JUAN 29-7 UNIT	563	BURLNGTN RE OG CO LP	24 29N 7W NE NW SW	NM	RIO ARRIBA	3050	
30045274530100	ROSA UNIT	235	WILLIAMS PROD CO	9 31N 6W SE NW NE	NM	SAN JUAN	3218	3230
30039250490000	NE BLANCO UNIT	475	BLACKWOOD&NICHLS CO	20 30N 7W NW NE SW	NM	RIO ARRIBA	4179	4205
30039253380000	SAN JUAN 30-6 UNIT	498R	PHILLIPS PETRLM CO	30 30N 7W SW SW NE	NM	RIO ARRIBA	3945	3433
30039244290100	ROSA UNIT	217	WILLIAMS PROD CO	11 31N 6W NW SE NE	NM	RIO ARRIBA	3279	3279
30039244190000	CARRACAS UNIT 25 B	13	NASSAU RESOURCES INC	25 32N 4W NW SW SW	NM	RIO ARRIBA	4850	3710
30039244930100	ROSA UNIT	220	WILLIAMS PROD CO	13 31N 6W SW NE NE	NM	RIO ARRIBA	3342	3350
30039245230100	ROSA UNIT	210	WILLIAMS PROD CO	13 31N 6W NE SW SW	NM	RIO ARRIBA	3107	3108
30039245000100	ROSA UNIT	221	WILLIAMS PROD CO	18 31N 5W SW NE NE	NM	RIO ARRIBA	3339	3343
30039249700100	ROSA UNIT	268	WILLIAMS PROD CO	33 31N 5W SW NW NE	NM	RIO ARRIBA	3385	3385
30039243610100	ROSA UNIT COM	239	WILLIAMS PROD CO	2 31N 6W NE SE SW	NM	RIO ARRIBA	3153	3200
30045274440100	FEDERAL 32-8-26	2	SG INTEREST I LTD	26 32N 8W NE SW SW	NM	SAN JUAN	3643	3350
30045297180000	FLORANCE	70	CROSS TIMBERS OPR CO	20 27N 8W NW NW SE	NM	SAN JUAN	3385	
30045273360000	DAWSON GAS COM	1	AMOCO PROD CO	31 31N 8W N2 SW SW	NM	SAN JUAN	3156	3500
30045273370000	MOORE A	8	AMOCO PROD CO	4 30N 8W NE SW NE	NM	SAN JUAN	3113	3329
30045273390000	KERNIGHAN B	6	AMOCO PROD CO	29 31N 8W SE NW NE	NM	SAN JUAN	3446	3500
30045273480100	JOHNSTON FEDERAL	24	MERIDIAN OIL INC	12 30N 9W SW NE NE	NM	SAN JUAN	3010	2705
30045274590100	JOHNSTON FEDERAL	26	BURLNGTN RE OG CO LP	7 31N 9W NW SE NE	NM	SAN JUAN	3423	3423
30045274850100	BARNES GAS COM A	1	AMOCO PROD CO	23 32N 11W SE NW NE	NM	SAN JUAN	3206	3100
30045280120100	GARDNER C	5	KOCH EXPL CO	26 32N 9W SE NW SW	NM	SAN JUAN	3465	3460
30045280940100	QUINN	339	BURLNGTN RE OG CO LP	20 31N 8W SE NW SW	NM	SAN JUAN	3671	3439
30045295670000	SAN JUAN 32-7 UNIT	220	PHILLIPS PETRLM CO	5 31N 7W SW SW	NM	SAN JUAN	3943	3357
30045269080100	PAGE	101	BURLNGTN RE OG CO LP	18 32N 10W NW SW SW	NM	SAN JUAN	3122	2889
30045286410000	SULLIVAN GAS COM E	1	AMOCO PROD CO	22 32N 10W SW SE SW	NM	SAN JUAN	2888	2909
30045278480100	SAN JUAN 32-9 UNIT	252	BURLNGTN RE OG CO LP	5 31N 9W SW NE NE	NM	SAN JUAN	3570	3600
30045283200000	NORTHWEST BLANCO UNIT	404R	BLACKWOOD&NICHLS CO	34 31N 7W NW SW NW	NM	SAN JUAN	3753	3785
30045298740000	SAN JUAN 32-7 UNIT	240	PHILLIPS PETRLM CO	20 32N 7W NW SW NW	NM	SAN JUAN	3094	3172
30045245030100	USA	2	MERIDIAN OIL INC	24 32N 13W NE SW SW	NM	SAN JUAN	7410	3434
30045284540000	GRASSY CANYON	3	CNG DEVELOPMENT CO	31 32N 7W SW NW NE	NM	SAN JUAN	3711	3600
30045284800000	GRASSY CANYON	4	CNG DEVELOPMENT CO	31 32N 7W SW NW NE	NM	SAN JUAN	3926	3600
30045277080100	NORTHEAST BLANCO UNIT	488	DEVON ENERGY CORP	24 31N 7W SE NW SW	NM	SAN JUAN	3357	3345
30039242910100	SAN JUAN 32-5 UNIT	106	ENERGEN RES CORP	26 32N 6W SW SE SW	NM	RIO ARRIBA	3243	3200
30045299310000	SAN JUAN 32-7 UNIT	243	PHILLIPS PETRLM CO	19 32N 7W SW NW SW	NM	SAN JUAN	3854	3150
05067071830100	SOUTHERN UTE TRIBAL LL	1	AMOCO PROD CO	8 32N 10W NE SW SW	CO	LA PLATA	3134	3360
30039245010100	ROSA UNIT	238	WILLIAMS PROD CO	3 31N 6W NE	NM	RIO ARRIBA	3142	3180
05067087760000	FC SOUTHERN UTE COM 5 FT	2	BP AMERICA PRODTN CO	9 33N 9W NW	CO	LA PLATA	3050	2970
05067072250100	SOUTHERN UTE 33-10	2-4	RED WILLOW PROD CO	2 33N 10W NW SE NW	CO	LA PLATA	2796	
05067069780100	SOUTHERN UTE	22-2	44 CANYON LLC	22 33N 11W N2 NW NE	CO	LA PLATA	3056	
05067071110100	SOUTHERN UTE 32-10	4-2	ARCO OIL & GAS CORP	4 32N 10W NW SE SW	CO	LA PLATA	3220	3220
05067071170100	SOUTHERN UTE 32-10	14-3	VASTAR RESOURCES INC	14 32N 10W SE NW SW	CO	LA PLATA	3110	3080
05067071190100	SOUTHERN UTE 32-10	15-2	ARCO OIL & GAS CORP	15 32N 10W SW NW NE	CO	LA PLATA	3638	2900
05067071690100	SOUTHERN UTE 32-9	22-5	VASTAR RESOURCES INC	22 32N 9W NW SW SE	CO	LA PLATA	3647	3680
05067087800000	REA EARL GAS UNIT	2	BP AMERICA PRODTN CO	32 34N 8W SW NW NE	CO	LA PLATA	3532	3566
05067071810100	SOUTHERN UTE 32-9	21-5	VASTAR RESOURCES INC	21 32N 9W NE NE NE	CO	LA PLATA	3407	3400
05067069420100	SOUTHERN UTE FC 33-11	12-4	RED WILLOW PROD CO	12 33N 11W SW SE NW	CO	LA PLATA	3976	3892
05067072220100	SOUTHERN UTE 32-10	5-5	RED WILLOW PROD CO	5 32N 10W NE SW NE	CO	LA PLATA	3906	3906
05067072350100	SOUTHERN UTE TRIBAL MM	1	AMOCO PROD CO	8 32N 10W SE NW NE	CO	LA PLATA	3605	3800
05067073110100	SOUTHERN UTE 503	5-35	AMOCO PROD CO	35 33N 10W SW NE NW	CO	LA PLATA	3145	3240

Table 2

Deviated Wells Derived From HIS Database

API	Lease Name	Well Num	Operator Name	Location	State	County Name	Driller TD	Proj Depth
05067071720100	ELDRIDGE	25-1	AMOCO PROD CO	25 33N 11W NE SW SE	CO	LA PLATA	3250	3050
30039270410000	ROSA UNIT	381	WILLIAMS PROD CO	11 31N 6W NW SW NW	NM	RIO ARRIBA	4100	3435
30045268400100	SCOTT	100	BURLNGTN RE OG CO LP	29 32N 10W NW SE NE	NM	SAN JUAN	2986	2990
30039245310200	SAN JUAN 31-6 UNIT	213	PHILLIPS PETRLM CO	5 30N 6W SW NE SW	NM	RIO ARRIBA	3485	3150
30039273010000	BLANCO NORTHEAST UNIT	407A	DEVON ENERGY PROD	21 30N 7W SE NE SE	NM	RIO ARRIBA	3667	3620
30039264830000	CARRACAS 36A	1	VASTAR RESOURCES INC	36 32N 5W NW NE NE	NM	RIO ARRIBA	4024	3968
30039264840000	CARRACAS 33 B	11	VASTAR RESOURCES INC	33 32N 4W SE NW NW	NM	RIO ARRIBA	4186	5227
30039247330100	NORTHEAST BLANCO UNIT	499	DEVON ENERGY CORP	20 31N 6W NW SE SE	NM	RIO ARRIBA	3205	3250
30039264850000	CARRACAS 17B	14	VASTAR RESOURCES INC	17 32N 4W NW SE SW	NM	RIO ARRIBA	4360	4691
30039232720200	ARBOLES 29 A	1	VASTAR RESOURCES INC	29 32N 4W SW NE SW	NM	RIO ARRIBA	4150	4175
05067074550100	DUNKEL ELMER GAS UNIT A	1	AMOCO PROD CO	12 33N 10W NE NW SE	CO	LA PLATA	2625	2772
30039269490000	ROSA UNIT	379	WILLIAMS PROD CO	8 31N 5W SW NE SW	NM	RIO ARRIBA	5300	3700
30039252190100	ROSA UNIT	315	WILLIAMS PROD CO	30 31N 4W NE NE SW	NM	RIO ARRIBA	3580	3550
30039243380100	SAN JUAN 32-5 UNIT	101	ENERGEN RES CORP	23 32N 6W SW SE NE	NM	RIO ARRIBA	3167	3150
30039244260100	ROSA UNIT	213	WILLIAMS PROD CO	23 31N 6W SE NW NE	NM	RIO ARRIBA	3127	3127
30039244690100	SAN JUAN 30-6 UNIT	476	BURLNGTN RE OG CO LP	28 30N 6W SW NE NE	NM	RIO ARRIBA	3264	3260
30039249140100	SAN JUAN 29-7 UNIT	581	BURLNGTN RE OG CO LP	1 29N 7W SW NE SW	NM	RIO ARRIBA	3677	
30039244940100	ROSA UNIT	226	WILLIAMS PROD CO	12 31N 6W NE SW NE	NM	RIO ARRIBA	3106	3100
30039247720000	RINCON	254	UNION OIL CO OF CAL	20 27N 6W NW SE NE	NM	RIO ARRIBA	3595	3140
05067087730000	BARNES GAS UNIT B	2	BP AMERICA PRODTN CO	1 33N 9W SW NE NE	CO	LA PLATA	3134	3030
05067061490100	ARGENTA UTE	4	SG INTEREST I LTD	6 33N 10W NW SE NW	CO	LA PLATA	3910	3925
05067066460100	BURCH SAM	11	FOUR STAR O&G COMP	3 32N 9W NW SE NW	CO	LA PLATA	5877	3650
30039267410000	ROSA UNIT	361	WILLIAMS PROD CO	16 31N 5W SE NE SW	NM	RIO ARRIBA	5000	3082

Table 2

Deviated Wells
With Directional Survey Information
and Having (MD-TVD)>300 Ft
San Juan Basin, Fruitland Coal

API	LEASE	OPERATOR	LOCATION	STATE	COUNTY	Completion Date Deviated Well	Driller TD
05067071190000	SO UTE 32-10 #15-2	BP AMERICA PRODUCTION CO	15 32N 10W SW NW NE	CO	LA PLATA	1/1/1990	3,638
05067072690100	DAVE A	RED WILLOW PRODUCTION CO	7 33N 10W NW SE SE	CO	LA PLATA	4/1/1999	4,516
05067081760000	BLACK RIDGE SU#17-3	CHEVRON U S A INCORPORAT	17 33N 10W NE SE NW	CO	LA PLATA	2/1/1999	4,953
05067081780000	BLACK RIDGE SU 17-4	CHEVRON U S A INCORPORAT	17 33N 10W NE SE NW	CO	LA PLATA	8/1/1999	4,538
05067082120000	SO UTE FC 33-10 7-4	RED WILLOW PRODUCTION CO	7 33N 10W NE SE NW	CO	LA PLATA	3/1/2000	4,358
05067083540000	SO UTE 33-9 #29-4	BP AMERICA PRODUCTION CO	29 33N 9W SE SW NW	CO	LA PLATA	4/1/2001	3,601
05067083880000	SIMON L&C 15U2R #2	BP AMERICA PRODUCTION CO	15 34N 9W NW NW SW	CO	LA PLATA	7/1/2001	3,405
05067087410000	WEST ANIMAS UNIVERSITY	CHEVRON U S A INCORPORAT	9 34N 9W NE SE SW	CO	LA PLATA	10/1/2002	2,540
30039253150000	NORTHEAST BLANCO UNIT	DEVON ENERGY CORPORATION	20 30N 7W SE NE NW	NM	RIO ARRIBA	11/1/1993	4,034
30039253380000	SAN JUAN 30 6 UNIT NP	BURLINGTON RESOURCES O&G	30G 30N 7W SW SW NE	NM	RIO ARRIBA	1/1/1996	3,945
30045282220000	NORTHEAST BLANCO UNIT	DEVON ENERGY CORPORATION	12 30N 8W SW NE SE	NM	SAN JUAN	11/1/1991	3,850
30045283200000	NORTHEAST BLANCO UNIT	DEVON ENERGY CORPORATION	34E 31N 7W NW SW NW	NM	SAN JUAN	4/1/1991	3,753
30045284800000	GRASSY CANYON	DOMINION EXPLORATION & P	31 32N 7W SW NW NE	NM	SAN JUAN	8/1/1991	3,926

Table 3

Horizontal, Deviated and Vertical Wells
Used for Performance Comparison

LEASE	Well No	API	Location (Twp-Rng-Sec)	TYPE	First Prod Month/Yr	Last Prod Month/Yr
HUGHES B	18	30045278860000	29N-8W-21		May-91	Aug-94
HUGHES B	20	30045282200000	29N-8W-21		May-91	Nov-03
HUGHES B	18R	30045289950000	29N-8W-21	H	Sep-94	Nov-03
SUNRAY H COM	200	30045270200000	30N-10W-11		Apr-90	Nov-03
SUNRAY H	201	30045272210000	30N-10W-11	H	Mar-90	Nov-03
SAN JUAN 30 6 UNIT	476	30039244690000	30N-6W-28		Feb-90	Nov-03
SAN JUAN 30 6 UNIT	477	30039244920000	30N-6W-28	H	Jul-90	Nov-03
SAN JUAN 30 6 UNIT	478	30039244700000	30N-6W-29		May-90	Nov-03
SAN JUAN 30 6 UNIT	479	30039246000000	30N-6W-29	H	Jun-90	Nov-03
NORTHEAST BLANCO UNIT	479	30039244900000	30N-7W-20		Sep-90	Dec-90
NORTHEAST BLANCO UNIT	413R	30039249460000	30N-7W-20		Feb-91	Nov-03
NORTHEAST BLANCO UNIT	475	30039250490000	30N-7W-20		Apr-91	Nov-03
NORTHEAST BLANCO UNIT	479R	30039253150000	30N-7W-20	D	Nov-93	Nov-03
NORTHEAST BLANCO UNIT	413A	30039272990000	30N-7W-20		Oct-03	Nov-03
SAN JUAN 30 6 UNIT	498	30039249470000	30N-7W-30		Dec-91	Jun-96
SAN JUAN 30 6 UNIT	499	30039249480000	30N-7W-30		Aug-91	Jan-02
SAN JUAN 30 6 UNIT NP	498R	30039253380000	30N-7W-30	D	Jan-96	Nov-03
NORTHEAST BLANCO UNIT	437	30045271690000	30N-8W-12		Dec-90	Nov-03
NORTHEAST BLANCO UNIT	467	30045273530000	30N-8W-12		Dec-90	Nov-03
NORTHEAST BLANCO UNIT	461	30045282220000	30N-8W-12	D	Nov-91	Nov-03
FLORANCE	103	30045201470000	30N-8W-6		Oct-82	Jan-94
HOWELL G COM	300	30045269130000	30N-8W-6		Dec-89	Nov-03
FLORANCE H	3	30045273300000	30N-8W-6		Feb-91	Nov-03
FLORANCE H	37	30045292050000	30N-8W-6	H	Apr-95	Nov-99
FLORANCE H	37R	30045292050001	30N-8W-6	H	Jun-03	Nov-03
ROSA UNIT	310	30039248630000	31N-4W-26	H	Aug-93	Sep-03
ROSA UNIT	309	30039249490000	31N-4W-26		Aug-93	Nov-03
ROSA UNIT	322	30039249500000	31N-5W-23		Aug-98	Nov-03
ROSA UNIT	351	30039262460000	31N-5W-11		Nov-00	Nov-03
ROSA UNIT	345	30039262480000	31N-5W-23		Oct-00	Nov-03
ROSA UNIT	354	30039264120000	31N-5W-19		Jun-01	Nov-03
ROSA UNIT	371	30039272390000	31N-5W-13	H	Sep-02	Nov-03
NORTHEAST BLANCO UNIT	466	30045277210000	31N-7W-34		Sep-91	Nov-03
NORTHEAST BLANCO UNIT	404R	30045283200000	31N-7W-34	D	Apr-95	Mar-95
SO UTE 32-10 #15-2	2	05067071190000	32N-10W-15	D	Jan-90	Nov-03
SO UTE 32-10 #15-3	3	05067073420000	32N-10W-15		Aug-90	Nov-03
HEIZER	100	30045269500000	32N-10W-15		Jun-90	Nov-03
BONDS COM	100	30045276880000	32N-10W-15		Jul-90	Nov-03
KEYS GAS COM E	1	30045208330000	32N-10W-27		Jun-73	Jul-93
KEYS GAS COM G	1	30045213120000	32N-10W-27		Aug-83	Mar-89
KEYS GAS COM F	1PI	30045254760000	32N-10W-27		May-74	Jul-74
PAYNE	11	30045268040100	32N-10W-27	H	Sep-96	Nov-03
KEYS GAS COM G	1R	30045268560000	32N-10W-27		Mar-89	Nov-03
PAYNE	11S	30045313230000	32N-10W-27		Jun-03	Nov-03
SO UTE 32-11 #18-1	1	05067077380000	32N-11W-18		Feb-94	Dec-03
SO UTE 32-11 #18-2	2	05067078880000	32N-11W-18		Mar-94	Dec-03
FC FEDERAL COM	8	30045278310000	32N-11W-18	H	Sep-95	Aug-95
FC FEDERAL COM	7	30045280700000	32N-11W-18		Feb-92	Nov-03
UTE 32-11 #401	401	05067076060000	32N-11W-4		Feb-94	Dec-93
UTE 32-11 #402H	402H	05067076220000	32N-11W-4	H	Jun-93	Nov-03
CARRACAS UNIT 34 B	9	30039243480000	32N-4W-34	H	Dec-90	Nov-03
CARRACAS UNIT FR	113	30039244030000	32N-4W-34		Aug-91	Nov-03
SAN JUAN 32 5 UNIT NP	100	30039242680000	32N-6W-23	H	Sep-89	Nov-03
SAN JUAN 32 5 UNIT NP	101	30039243380000	32N-6W-23		Dec-99	Jun-99
SAN JUAN 32 5 UNIT	101S	30039272630000	32N-6W-23		Aug-03	Nov-03
ANDERSON 32-6 #5-1	1	05067080840000	32N-6W-5		Oct-97	Jun-02
DUELL 32-6 #5-1	5-1	05067086700000	32N-6W-5		May-02	Nov-03
ANDERSON	1R	05067087460000	32N-6W-5	H	Nov-02	Dec-03
PAYNE #1-8	1	05067066630000	32N-6W-8		Dec-01	May-01
PENROSE #1R	1R	05067086980000	32N-6W-8	H	May-02	Dec-03

Table 4

Horizontal, Deviated and Vertical Wells
Used for Performance Comparison

LEASE	Well No	API	Location (Twp-Rng-Sec)	TYPE	First Prod Month/Yr	Last Prod Month/Yr
ALLISON UNIT	134	30045271860000	32N-6W-8		Nov-89	Nov-03
ALLISON UNIT COM	150	30045301540000	32N-6W-8		Nov-00	Nov-03
GRASSY CANYON	3	30045284540000	32N-7W-31		Aug-91	Nov-03
GRASSY CANYON	4	30045284800000	32N-7W-31	D	Aug-91	Nov-03
SO UTE 32-9 #12-1H	1H	05067072910000	32N-9W-12	H	Feb-90	Nov-03
SO UTE 32-9 #12-2	2	05067072920000	32N-9W-12		Feb-90	Nov-03
SO UTE 32-9 #12-4	4	05067081620000	32N-9W-12		Oct-98	Nov-03
SO UTE 32-9 #12-3	3	05067081660000	32N-9W-12		Oct-98	Nov-03
SAN JUAN 32 FEDERAL 12	1	30045297620000	32N-9W-12		Dec-99	Nov-03
SAN JUAN 32 FEDERAL 12	1A	30045316080000	32N-9W-12		Jul-03	Nov-03
BLACK RIDGE SU#17-2	2	05067076560000	33N-10W-17		Oct-95	Nov-03
BLACK RIDGE SU#17-1	1	05067077930000	33N-10W-17		Oct-95	Nov-03
BLACK RIDGE SU#17-3	3	05067081760000	33N-10W-17	D	Feb-99	Nov-03
BLACK RIDGE SU 17-4	4	05067081780000	33N-10W-17	D	Aug-99	Nov-03
SOUTE FC 33-10 #7-3	207	05067069220000	33N-10W-7		Dec-92	Dec-03
SO UTE FC 33-10 7-1	1	05067072690000	33N-10W-7		Oct-90	Aug-98
DAVE A	1	05067072690100	33N-10W-7	D	Apr-99	Dec-03
SOUTE FC 33-10 #7-2	206	05067076950000	33N-10W-7		Jan-93	Dec-03
SO UTE FC 33-10 7-4	7-4	05067082120000	33N-10W-7	D	Mar-00	Dec-03
SO UTE J-26 #1	1	05067070610000	33N-11W-26	H	Aug-88	Nov-03
SOUTHE	3	05067072820000	33N-11W-26		Sep-90	Apr-99
SOUTHE	3	05067072820100	33N-11W-26		May-99	Nov-03
SO UTE 33-9 #29-1	1	05067073540000	33N-9W-29		Nov-92	Aug-92
SO UTE TRIBAL GU JJ	1	05067076430000	33N-9W-29		Apr-93	Nov-03
SO UTE 33-9 #29-2	2	05067081430000	33N-9W-29		Sep-98	Nov-03
SO UTE 33-9 #29-4	29-4	05067083540000	33N-9W-29	D	Apr-01	Nov-03
LYLE S	1	05067069110000	33N-9W-7		Jun-87	Jul-99
LYLE S	1	05067069110100	33N-9W-7		Sep-99	Nov-03
SHORT ALVA GU A #1	1	05067071460000	33N-9W-7	H	Mar-91	Nov-03
SHORT ALVA GU A #2	2	05067084250000	33N-9W-7		Nov-01	Nov-03
SHORT LYLE GU A #2	2	05067086500000	33N-9W-7		Apr-02	Nov-03
SIMON L & C #15-2	2	05067066970000	34N-9W-15		Oct-87	Mar-94
LINDNER GU A #1	1	05067074190000	34N-9W-15		Mar-89	Nov-03
SIMON L&C 15U-2R UT	2R	05067074230000	34N-9W-15		Mar-94	Nov-03
SIMON L&C 15U2R #2	2	05067083880000	34N-9W-15	D	Jul-01	Nov-03
DUSTIN GU 9-1 #1	1	05067066510000	34N-9W-9		Jan-83	Nov-03
CRAIG HELEN GU #1	1	05067069600000	34N-9W-9		Aug-88	Nov-03
W A UNIVERSITY 9-1	1	05067078400000	34N-9W-9		Jun-93	Nov-03
W A UNIVERSITY 9-2	2	05067078640000	34N-9W-9		Nov-92	Nov-03
DUSTIN GU 9-1 #2	2	05067084840000	34N-9W-9		Oct-01	Nov-03
WEST ANIMAS UNIVERSITY	9-3	05067087410000	34N-9W-9	D	Oct-02	Dec-02

Table 4

Maximum Annual Rates and Estimated Ultimate Recovery for Comparison Wells

LEASE	Well No	API	Location (Twp-Rng-Sec)	Life	TYPE	Remaining Gas	Ultimate Gas	Cum Gas	Qmax Year Monthly Average	Last Year Monthly Average	Aries Decline
HUGHES B	18	30045278860000	29N-8W-21				103	103	3,098	2,237	
HUGHES B	20	30045282200000	29N-8W-21	21.7		104	504	400	4,120	2,074	10.0
HUGHES B	18R	30045289950000	29N-8W-21	39.3	H	323	814	491	5,661	3,227	10.0
SUNRAY H COM	200	30045270200000	30N-10W-11	0.1		1	221	220	3,169	958	10.0
SUNRAY H	201	30045272210000	30N-10W-11	0.1	H	1	181	180	1,371	940	10.0
SAN JUAN 30 6 UNIT	476	30039244690000	30N-6W-28	17.5		2,352	12,907	10,555	109,023	42,098	18.1
SAN JUAN 30 6 UNIT	477	30039244920000	30N-6W-28	20.9	H	3,453	22,566	19,113	204,555	59,692	16.5
SAN JUAN 30 6 UNIT	478	30039244700000	30N-6W-29	45.8		6,827	26,674	19,847	168,440	61,678	10.0
SAN JUAN 30 6 UNIT	479	30039246000000	30N-6W-29	21.4	H	2,867	17,190	14,323	135,445	38,167	15.0
NORTHEAST BLANCO UNIT	479	30039244900000	30N-7W-20				1	1	101	101	
NORTHEAST BLANCO UNIT	413R	30039249460000	30N-7W-20	41.3		3,669	14,405	10,736	122,370	33,170	10.0
NORTHEAST BLANCO UNIT	475	30039250490000	30N-7W-20	22.3		1,778	8,180	6,401	74,688	15,656	11.6
NORTHEAST BLANCO UNIT	479R	30039253150000	30N-7W-20	27.6	D	2,827	9,801	6,973	91,696	27,570	10.7
NORTHEAST BLANCO UNIT	413A	30039272990000	30N-7W-20			643	650	7	3,541	3,541	10.0
SAN JUAN 30 6 UNIT	498	30039249470000	30N-7W-30				41	41	1,630	0	
SAN JUAN 30 6 UNIT	499	30039249480000	30N-7W-30				786	786	11,010	124	
SAN JUAN 30 6 UNIT NP	498R	30039253380000	30N-7W-30	0.1	D	1	85	84	1,049	1,049	10.0
NORTHEAST BLANCO UNIT	437	30045271690000	30N-8W-12	26.2		2,019	5,690	3,671	39,227	19,655	10.0
NORTHEAST BLANCO UNIT	467	30045273530000	30N-8W-12	18.8		1,087	5,034	3,946	50,961	14,055	11.5
NORTHEAST BLANCO UNIT	461	30045282220000	30N-8W-12	17.8	D	1,670	5,271	3,601	39,258	26,695	15.5
FLORANCE	103	30045201470000	30N-8W-6				148	148	2,549	43	
HOWELL G COM	300	30045269130000	30N-8W-6	50		1,822	9,439	7,617	90,060	16,904	10.0
FLORANCE H	3	30045273300000	30N-8W-6	35.1		3,620	18,457	14,837	163,551	33,089	10.0
FLORANCE H	37	30045292050000	30N-8W-6		H		45	45	2,985	0	
FLORANCE H	37R	30045292050001	30N-8W-6		H	48	61	14	1,235	2,265	
ROSA UNIT	310	30039248630000	31N-4W-26		H		191	191	2,893	236	
ROSA UNIT	309	30039249490000	31N-4W-26	5.3		81	524	442	9,016	1,980	10.0
ROSA UNIT	322	30039249500000	31N-5W-23	8.7		210	433	223	5,952	3,123	10.11
ROSA UNIT	351	30039262460000	31N-5W-11	1.2		20	100	80	2,975	1,513	18.63
ROSA UNIT	345	30039262480000	31N-5W-23	16.3		673	893	220	7,438	7,438	10.42
ROSA UNIT	354	30039264120000	31N-5W-19	12.3		792	1,074	282	12,940	12,940	18.1
ROSA UNIT	371	30039272390000	31N-5W-13	15.2	H	623	739	115	7,636	7,636	11.1
NORTHEAST BLANCO UNIT	466	30045277210000	31N-7W-34	17		2,863	15,092	12,229	119,887	59,279	20.0
NORTHEAST BLANCO UNIT	404R	30045283200000	31N-7W-34	19	D	3,740	15,199	11,459	119,793	64,053	18.9
SO UTE 32-10 #15-2	2	05067071190000	32N-10W-15	15.8	D	1,580	10,040	8,459	99,825	29,526	18.2
SO UTE 32-10 #15-3	3	05067073420000	32N-10W-15	26.4		4,777	20,459	15,682	151,908	65,435	13.9
HEIZER	100	30045269500000	32N-10W-15	21.3		6,274	27,253	20,979	310,139	120,496	19.1
BONDS COM	100	30045276880000	32N-10W-15	23.7		6,864	24,950	18,086	273,182	120,741	17.3
KEYS GAS COM E	1	30045208330000	32N-10W-27				195	195	4,805	61	
KEYS GAS COM G	1	30045213120000	32N-10W-27				272	272	20,300	20,300	
KEYS GAS COM F	1PI	30045254760000	32N-10W-27				0	0	30	30	
PAYNE	11	30045268040100	32N-10W-27	11.8	H	1,035	4,752	3,717	56,864	23,693	21.7
KEYS GAS COM G	1R	30045268560000	32N-10W-27	13.1		1,254	9,514	8,260	71,760	26,565	20.6
PAYNE	11S	30045313230000	32N-10W-27	21.4		1,074	1,126	53	8,744	8,744	10.0
SO UTE 32-11 #18-1	1	05067077380000	32N-11W-18	25.3		1,940	7,051	5,112	102,998	21,079	10.5
SO UTE 32-11 #18-2	2	05067078880000	32N-11W-18	15.6		837	3,953	3,116	73,993	11,922	13.7
FC FEDERAL COM	8	30045278310000	32N-11W-18	5.3	H	81	488	407	5,825	1,807	10.0
FC FEDERAL COM	7	30045280700000	32N-11W-18	2.3		25	396	370	5,003	1,461	10.0
UTE 32-11 #401	401	05067076060000	32N-11W-4	4.8		145	4,810	4,665	112,845	4,820	24.7
UTE 32-11 #402H	402H	05067076220000	32N-11W-4	19.3	H	3,187	14,705	11,518	167,007	56,412	18.0
CARRACAS UNIT 34 B	9	30039243480000	32N-4W-34		H	0	167	167	2,452	203	
CARRACAS UNIT FR	113	30039244030000	32N-4W-34	8.4		131	1,033	902	11,720	2,370	10.0
SAN JUAN 32 5 UNIT NP	100	30039242680000	32N-6W-23		H	2,091	2,311	221	12,453	12,453	10.0
SAN JUAN 32 5 UNIT NP	101	30039243380000	32N-6W-23	8.9		171	277	106	2,817	2,817	10.0
SAN JUAN 32 5 UNIT	101S	30039272630000	32N-6W-23			1,159	1,182	23	5,743	5,743	10.0
ANDERSON 32-6 #5-1	1	05067080840000	32N-6W-5				8	8	386	45	
DUELL 32-6 #5-1	5-1	05067086700000	32N-6W-5	32		1,221	1,438	217	10,138	10,138	10.0
ANDERSON	1R	05067087460000	32N-6W-5		H	4,512	4,668	156	10,883	10,883	variable
PAYNE #1-8	1	05067066630000	32N-6W-8				249	249	2,341	2,341	
PENROSE #1R	1R	05067086980000	32N-6W-8		H	10,059	10,379	320	23,343	23,343	variable
ALLISON UNIT	134	30045271860000	32N-6W-8	34		945	1,658	713	9,120	9,069	10.0
ALLISON UNIT COM	150	30045301540000	32N-6W-8	0.1		1	22	21	659	659	10.0

Table 5

Maximum Annual Rates and Estimated Ultimate Recovery for Comparison Wells

LEASE	Well No	API	Location (Twp-Rng-Sec)	Life	TYPE	Remaining Gas	Ultimate Gas	Cum Gas	Qmax Year Monthly Average	Last Year Monthly Average	Aries Decline
GRASSY CANYON	3	30045284540000	32N-7W-31	25.2		4,015	9,945	5,930	75,008	55,048	13.8
GRASSY CANYON	4	30045284800000	32N-7W-31	20.3	D	1,692	1,909	217	21,638	12,500	13.0
SO UTE 32-9 #12-1H	1H	05067072910000	32N-9W-12	13.3	H	1,069	3,319	2,250	33,470	22,238	19.3
SO UTE 32-9 #12-2	2	05067072920000	32N-9W-12	38.2		4,337	8,638	4,302	49,093	41,004	10.0
SO UTE 32-9 #12-4	4	05067081620000	32N-9W-12	23.8		2,281	4,176	1,896	36,516	27,368	12.3
SO UTE 32-9 #12-3	3	05067081660000	32N-9W-12	31.7		6,630	6,956	326	79,658	44,306	12.2
SAN JUAN 32 FEDERAL 12	1	30045297620000	32N-9W-12	19.3		815	1,185	371	9,123	9,123	10.0
SAN JUAN 32 FEDERAL 12	1A	30045316080000	32N-9W-12	11.5		716	789	74	14,672	14,672	18.9
BLACK RIDGE SU#17-2	2	05067076560000	33N-10W-17	27.3		4,250	9,517	5,267	65,925	44,048	12.8
BLACK RIDGE SU#17-1	1	05067077930000	33N-10W-17	26.3		3,691	8,387	4,696	76,362	40,786	12.8
BLACK RIDGE SU#17-3	3	05067081760000	33N-10W-17	21	D	1,952	3,896	1,944	43,967	25,977	13.5
BLACK RIDGE SU 17-4	4	05067081780000	33N-10W-17	24.8	D	3,895	7,670	3,774	86,392	54,722	14.1
SOUTE FC 33-10 #7-3	207	05067069220000	33N-10W-7	21.8		2,473	5,953	3,480	55,882	36,296	14.3
SO UTE FC 33-10 7-1	1	05067072690000	33N-10W-7				225	225	5,611	634	
DAVE A	1	05067072690100	33N-10W-7	29.6	D	4,828	8,395	3,567	65,743	60,858	12.1
SOUTE FC 33-10 #7-2	206	05067076950000	33N-10W-7	31.5		6,815	10,820	4,004	78,906	78,646	12.5
SO UTE FC 33-10 7-4	7-4	05067082120000	33N-10W-7	39.5	D	6,918	9,383	2,466	65,715	65,715	10.0
SO UTE J-26 #1	1	05067070610000	33N-11W-26	17.1	H	1,727	6,850	5,123	61,134	30,035	16.9
SOUTHE	3	05067072820000	33N-11W-26	14.7		5,221	11,795	6,574	178,211	156,801	27.9
SOUTHE	3	05067072820100	33N-11W-26	24.5		5,502	12,425	6,923	141,476	91,770	15.9
SO UTE 33-9 #29-1	1	05067073540000	33N-9W-29	15.3		1,153	3,061	1,908	33,248	20,705	16.4
SO UTE TRIBAL GU JJ	1	05067076430000	33N-9W-29	24.3		4,457	10,457	6,001	72,719	67,511	15.1
SO UTE 33-9 #29-2	2	05067081430000	33N-9W-29	23.4		1,780	3,122	1,342	24,310	19,900	11.2
SO UTE 33-9 #29-4	29-4	05067083540000	33N-9W-29	18.5	D	2,194	3,552	1,357	44,408	35,923	16.8
LYLE S	1	05067069110000	33N-9W-7				1,202	1,202	17,416	16,128	
LYLE S	1	05067069110100	33N-9W-7	38.3		5,333	8,029	2,696	58,830	48,171	10.0
SHORT ALVA GU A #1	1	05067071460000	33N-9W-7	20.8	H	2,241	6,157	3,915	42,218	32,129	14.5
SHORT ALVA GU A #2	2	05067084250000	33N-9W-7	27.7		4,910	6,428	1,518	63,753	63,565	13.2
SHORT LYLE GU A #2	2	05067086500000	33N-9W-7	34.1		2,941	3,454	512	27,262	27,262	10.0
SIMON L & C #15-2	2	05067066970000	34N-9W-15	19.9		1,062	1,923	862	27,058	9,911	10.7
LINDNER GU A #1	1	05067074190000	34N-9W-15	44.6		3,853	8,311	4,458	43,206	33,995	10.0
SIMON L&C 15U-2R UT	2R	05067074230000	34N-9W-15	17.3		1,322	2,809	1,486	19,810	19,810	14.8
SIMON L&C 15U2R #2	2	05067083880000	34N-9W-15	41.2	D	4,448	5,402	954	41,965	41,965	10.0
DUSTIN GU 9-1 #1	1	05067066510000	34N-9W-9	42.6		1,629	3,972	2,344		16,082	10.0
CRAIG HELEN GU #1	1	05067069600000	34N-9W-9	44.4		2,563	5,653	3,090	22,612	22,612	10.0
W A UNIVERSITY 9-1	1	05067078400000	34N-9W-9	19.8		2,628	5,606	2,979	38,204	24,522	16.4
W A UNIVERSITY 9-2	2	05067078640000	34N-9W-9			3,009	8,833	5,823	65,424	33,372	10.0
DUSTIN GU 9-1 #2	2	05067084840000	34N-9W-9	46		2,657	3,200	543	23,742	23,742	10.0
WEST ANIMAS UNIVERSITY	9-3	05067087410000	34N-9W-9		D		60	60	4,971	4,971	10.0

Table 5

Performance Indices of Horizontal Wells
Compared to Offset Vertical Wells

API	Vertical Well IP Date	Horizontal Well Completion Date	EUR MMcF	Max Annual Rate As Mcf/Mo	Performance Index
05067070610000	Aug-88	Aug-98	6,850	61,134	0.5
05067071460000	Mar-91	Mar-00	6,157	42,218	1.1
05067072910000	Feb-90	Aug-91	3,319	33,470	1.0
05067076220000	Jun-93	Apr-98	14,705	167,007	2.3
05067086980000	Jun-02	Jun-02	10,379	23,343	7.5
05067087460000	Nov-02	Nov-02	4,668	10,883	2.2
30039242680000	Mar-89	Mar-89	2,311	12,453	3.0
30039243480000	Dec-90	Dec-90	167	2,452	0.2
30039244920000	Mar-90	Apr-98	22,566	204,555	1.8
30039246000000	Jun-90	Apr-98	17,190	135,445	0.7
30039248630000	Aug-93	Aug-02	191	2,893	0.3
30039272390000	Sep-02	Sep-02	739	7,636	1.1
30045268040100	Sep-96	Sep-96	4,752	56,864	1.9
30045272210000	Apr-89	Apr-89	181	1,371	0.6
30045278310000	Feb-92	Mar-96	488	5,825	0.1
30045289950000	Sep-94	Sep-94	814	5,661	2.1
30045292050001	Apr-95	Jun-03	61	1,235	0.0

Notes: ***1)***

$$Performance\ Index = \frac{1}{2}\left(\frac{EUR_{Horizontal\ Well}}{EUR_{Average\ Offset\ Vertical\ Wells}}\right) + \frac{1}{2}\left(\frac{Max.\ Annual\ Rate_{Horizontal\ Well}}{Max.\ Annual\ Rate_{Average\ Offset\ Vertical\ Wells}}\right)$$

2) Considered Production Through November 2003

Table 6

Performance Indices of Deviated Wells
Compared to Offset Vertical Wells

API	Completion Date Deviated Well	EUR (MMcF)	Max Annual Rate As Mcf/Mo	Performance
05067071190000	1/1/1990	3,638	99,825	0.4
05067072690100	4/1/1999	4,516	65,743	1.4
05067081760000	2/1/1999	4,953	43,967	0.5
05067081780000	8/1/1999	4,538	86,392	1.0
05067082120000	3/1/2000	4,358	65,715	1.5
05067083540000	4/1/2001	3,601	44,408	0.8
05067083880000	7/1/2001	3,405	41,965	1.0
05067087410000	10/1/2002	2,540	4,971	0.1
30039253150000	11/1/1993	4,034	91,696	1.3
30039253380000	1/1/1996	3,945	1,049	0.2
30045282220000	11/1/1991	3,850	39,258	0.9
30045283200000	4/1/1991	3,753	119,793	1.0
30045284800000	8/1/1991	3,926	21,638	0.2

Notes:

1) $$\text{Performance Index} = \tfrac{1}{2}\left(\frac{EUR_{\text{Horizontal Well}}}{EUR_{\text{Average Offset Vertical Wells}}}\right) + \tfrac{1}{2}\left(\frac{\text{Max. Annual Rate}_{\text{Horizontal Well}}}{\text{Max. Annual Rate}_{\text{Average Offset Vertical Wells}}}\right)$$

2) Considered Production Through November 2003

Comparison of Average Rate between Horizontal and Offset Vertical Wells

API	Starting Date for Comparison	Avg Offset Rate	Avg Horizontal Well Rate	Delta	Ratio
		MCFD	MCFD	MCFD	
05067076220000	Jun-98	731	3,759	3,028	5.1
05067086980000	May-02	120	461	341	3.8
30045289950000	Sep-94	76	149	73	2.0
30039244920000	Mar-98	2,200	3,252	1,052	1.5
30045268040000	Sep-96	1,561	1,502	-59	1.0
05067087460000	Nov-02	369	314	-55	0.9
05067071460000	Apr-00	1,576	1,296	-280	0.8
30045272210000	Mar-90	46	36	-10	0.8
30039246000000	Mar-98	2,838	2,179	-659	0.8
30039242680000	Sep-89	59	40	-19	0.7
05067072910000	Feb-92	861	515	-346	0.6
05067070610000	Aug-98	4,351	1,585	-2,766	0.4
30039243480000	Dec-90	160	40	-120	0.2
30039248630000	Dec-02	66	11	-55	0.2
30045278310000	Feb-96	966	86	-880	0.1

Note: Considered production through September 2003

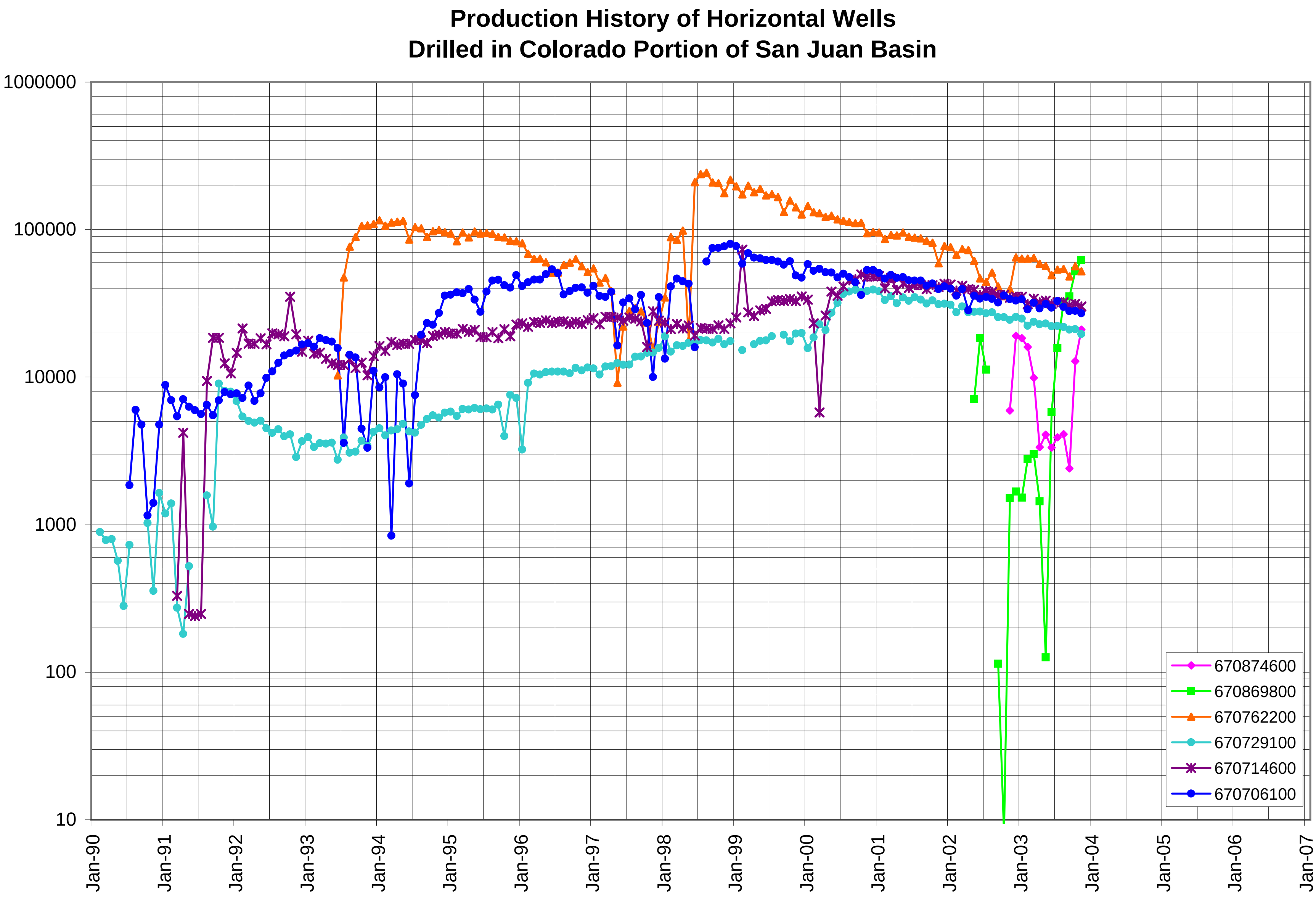
Table 8

Comparison of Average Rate between Directional and Offset Vertical Wells

API	Starting Date for Comparison	Avg Offset Rate	Avg Directional Well Rate	Delta	Ratio
		MCFD	MCFD	MCFD	
05067081780000	Oct-99	1,748	2,644	896	1.5
05067083880000	Jul-01	743	1,021	278	1.4
30039253150000	Jan-94	1,609	1,930	321	1.2
05067072690100	Sep-99	1,850	2,053	203	1.1
05067083540000	May-01	1,383	1,472	89	1.1
30045282220000	Nov-91	818	810	-8	1.0
05067087410000	Oct-02	710	654	-56	0.9
05067082120000	Jun-00	1,941	1,772	-169	0.9
30045283200000	Apr-91	2,768	2,512	-256	0.9
05067071190000	Jan-90	1,859	1,534	-325	0.8
30045284800000	Jan-99	2,140	598	-1,542	0.3
30039253380000	Jan-96	135	29	-106	0.2

Note: Considered production through September 2003

FIGURES



Production History of Horizontal Wells
Drilled in Colorado Portion of San Juan Basin
1000000
100000
10000
1000
100
10
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
670874600
670869800
670762200
670729100
670714600
670706100

Figure 1

Production History of Horizontal Wells
Drilled in New Mexico Portion of San Juan Basin

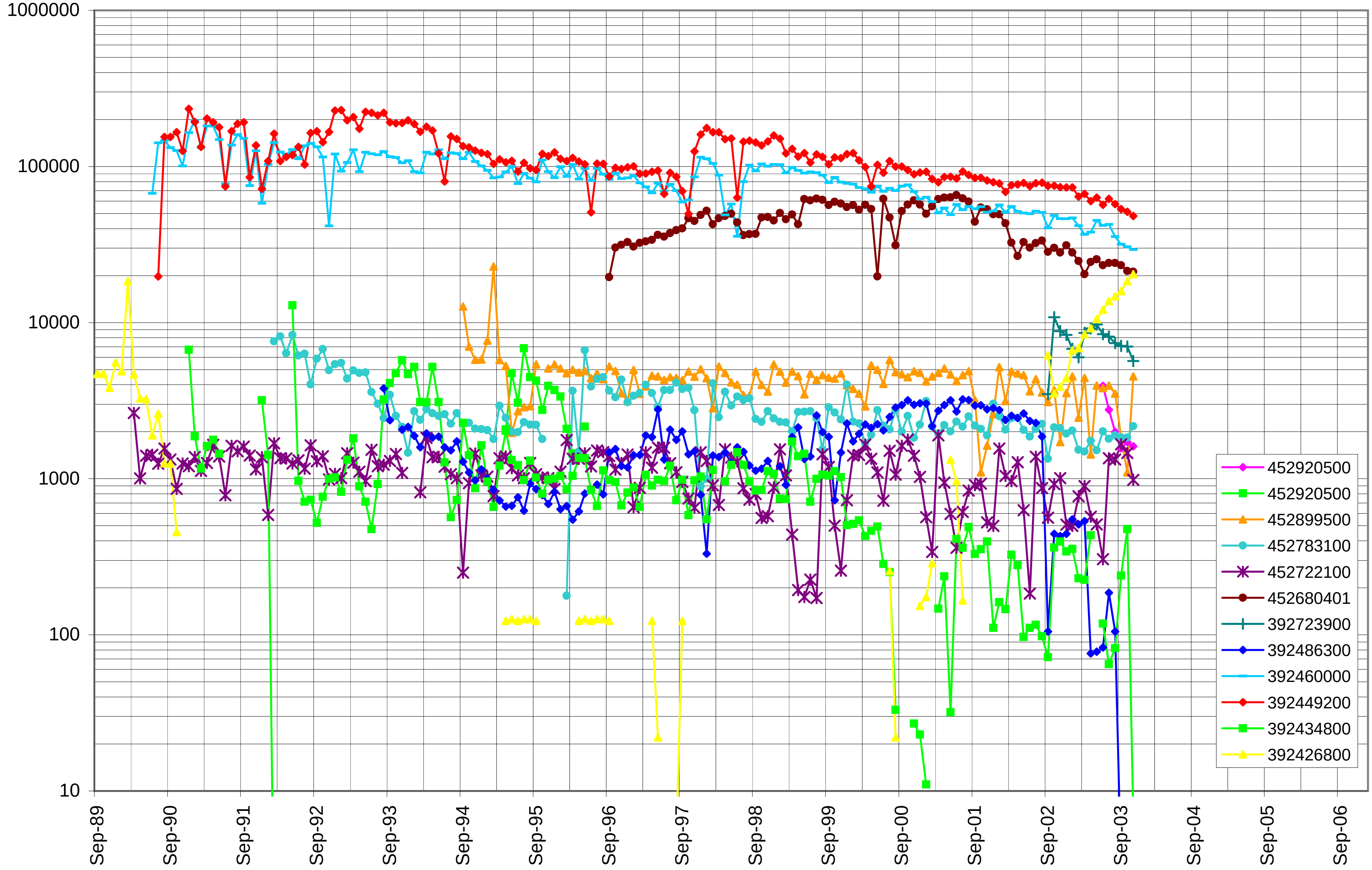


Figure 2

Production History of Deviated Wells
Drilled in Colorado Portion of San Juan Basin

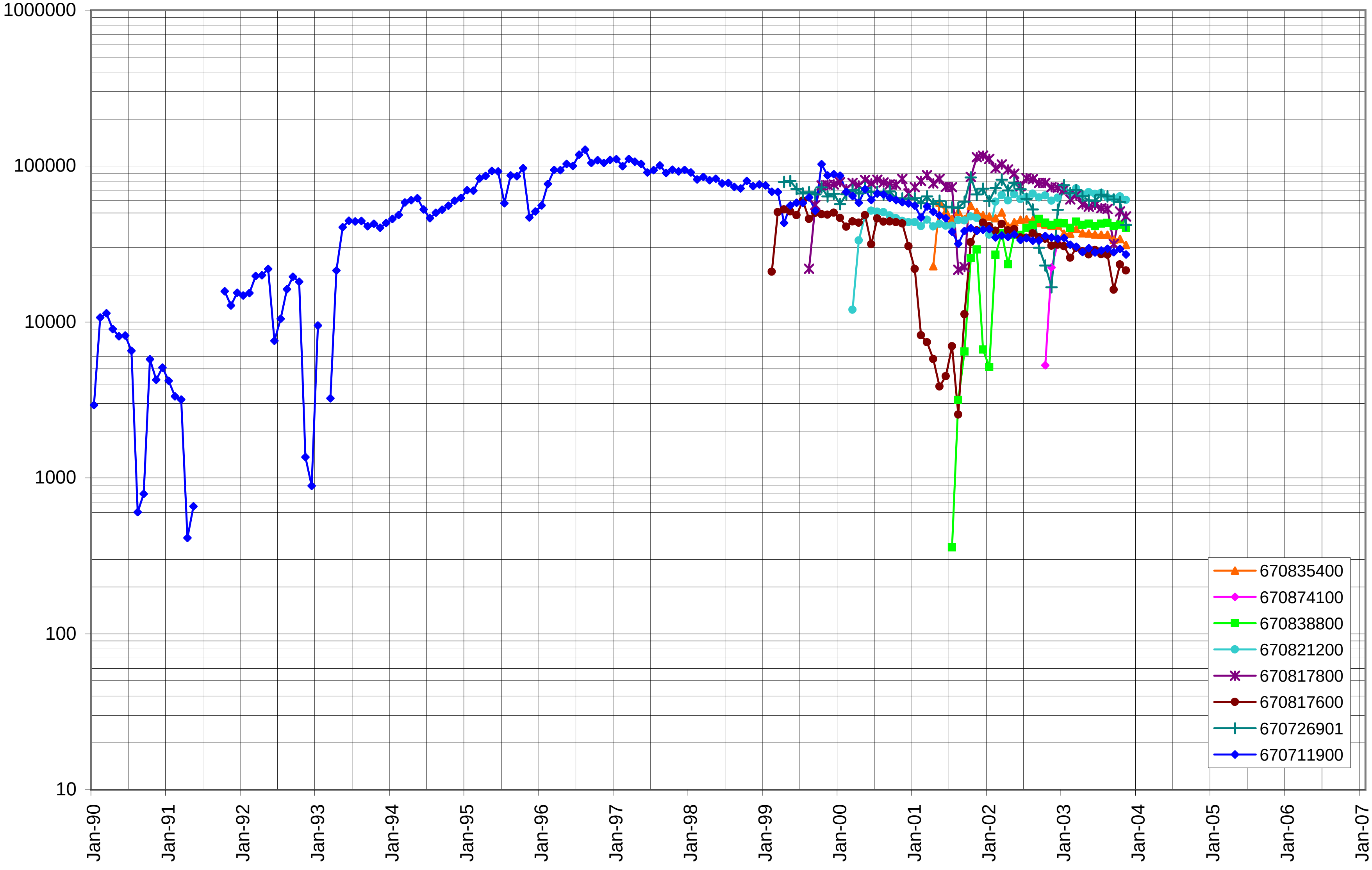
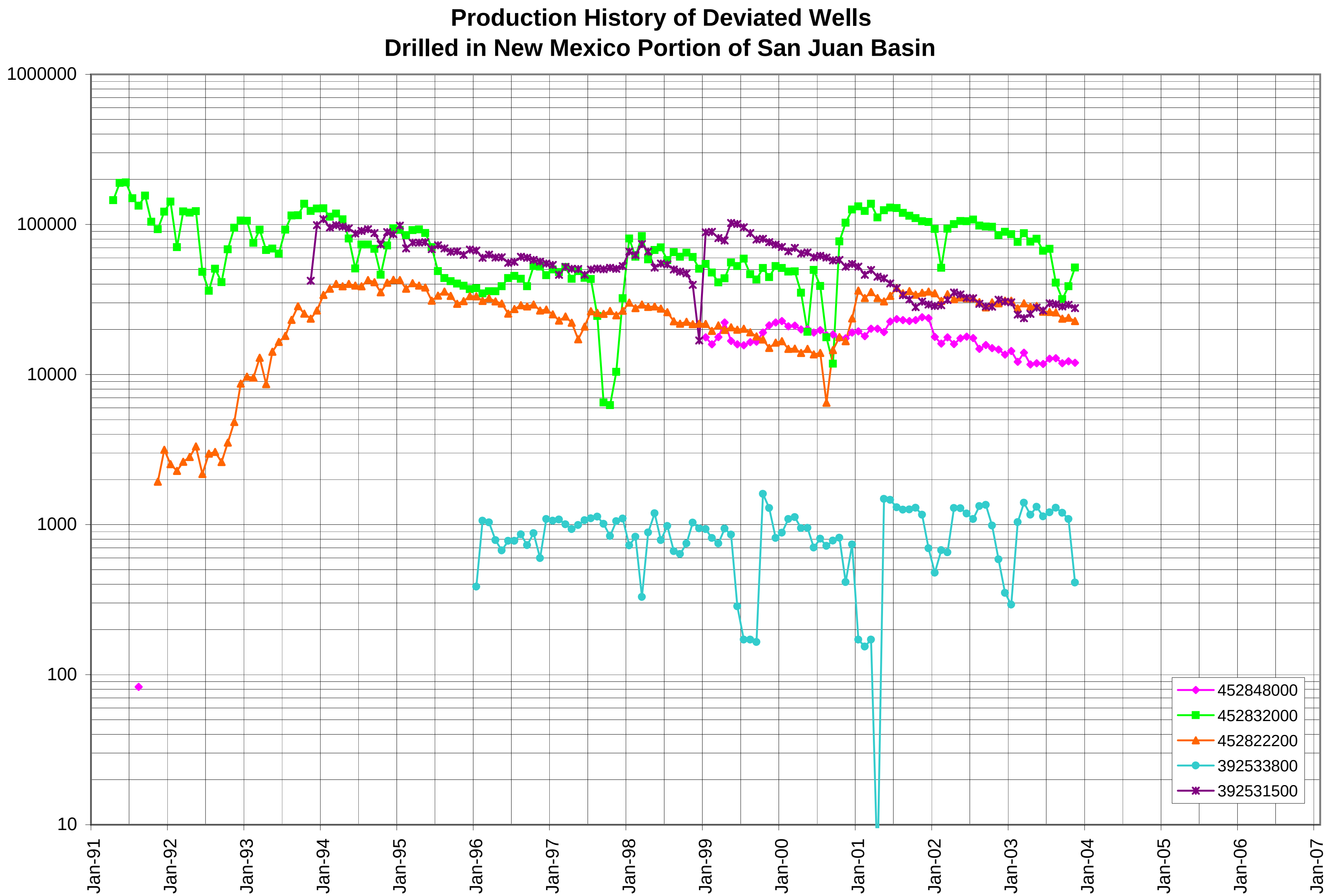


Figure 3



Production History of Deviated Wells
Drilled in New Mexico Portion of San Juan Basin
1000000
100000
10000
1000
100
10
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Jan-96
Jan-97
Jan-98
Jan-99
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
452848000
452832000
452822200
392533800
392531500

Figure 4